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A cumulative list of the parts affected this month can be found in the Reader Aids section at the end of this issue.

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Federal Register

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Thursday, August 11, 2011

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 520

[Docket No. FDA–2011–N–0003]

Oral Dosage Form New Animal Drugs; Change of Sponsor; Chlortetracycline; Sulfamethazine

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect a change of sponsor for five new animal drug applications (NADAs) from Fort Dodge Animal Health, Division of Wyeth Holdings Corp., a wholly owned subsidiary of Pfizer, Inc., to Boehringer Ingelheim Vetmedica, Inc.

DATES: This rule is effective August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Steven D. Vaughn, Center for Veterinary Medicine (HFV–100), Food and Drug Administration, 7520 Standish Pl., Rockville, MD 20855, 240–276–8300, e-mail: *steven.vaughn@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: Fort Dodge Animal Health, Division of Wyeth Holdings Corp., a wholly owned subsidiary of Pfizer, Inc., 235 East 42d St., New York, NY 10017 has informed FDA that it has transferred ownership of, and all rights and interest in, five approved NADAs (NADAs 055–012, 055–018, 055–039, 065–071, and 065–440) to Boehringer Ingelheim Vetmedica, Inc., 2621 North Belt Highway, St. Joseph, MO 64506–2002. Accordingly, the Agency is amending the regulations in 21 CFR part 520 to reflect the transfer of ownership.

This rule does not meet the definition of ''rule'' in 5 U.S.C. 804(3)(A) because it is a rule of ''particular applicability.'' Therefore, it is not subject to the congressional review requirements in 5 U.S.C. 801–808.

List of Subjects in 21 CFR Part 520

Animal drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 520 is amended as follows:

PART 520—ORAL DOSAGE FORM NEW ANIMAL DRUGS

■ 1. The authority citation for 21 CFR part 520 continues to read as follows:

Authority: 21 U.S.C. 360b.

■ 2. Revise § 520.445 to read as follows:

§ 520.445 Chlortetracycline and sulfamethazine powder.

(a) *Specifications.* Each pound of soluble powder contains chlortetracycline bisulfate equivalent to 102.4 grams (g) of chlortetracycline hydrochloride and sulfamethazine bisulfate equivalent to 102.4 g of sulfamethazine.

(b) *Sponsor.* See No. 000010 in § 510.600(c) of this chapter.

(c) *Related tolerances.* See §§ 556.150 and 556.670 of this chapter.

(d) *Conditions of use in swine.* Administer in drinking water as follows:

(1) *Amount.* 250 milligrams (mg) of chlortetracycline and 250 mg of sulfamethazine per gallon.

(2) *Indications for use.* For the prevention and treatment of bacterial enteritis; as an aid in the reduction of the incidence of cervical abscesses; and as an aid in the maintenance of weight gains in the presence of bacterial enteritis and atrophic rhinitis.

(3) *Limitations.* Use as the sole source of chlortetracycline and sulfonamide. Not to be used for more than 28 consecutive days. Withdraw 15 days before slaughter.

§ 520.445a [Removed]

■ 3. Remove § 520.445a.

§ 520.445b [Redesignated as § 520.441]

■ 4. Redesignate § 520.445b as § 520.441.

■ 5. Amend newly redesignated § 520.441 by revising paragraphs (b)(2), (b)(3), and the last sentence of paragraph (d)(4)(iii)(C) to read as follows:

§ 520.441 Chlortetracycline powder.

* * * * *

(b) * * *

(2) Nos. 046573 and 000010 for use as in paragraph (d) of this section.

(3) No. 000010 for use as in paragraphs (d)(4)(i)(A), (d)(4)(i)(B), and (d)(4)(ii) through (d)(4)(iv) of this section.

* * * * *

(d) * * *

(4) * * *

(iii) * * *

(C) * * * For Nos. 000010 and 021930, do not slaughter animals for food within 5 days of treatment. For No. 000010, do not slaughter animals for food within 24 hours of treatment.

* * * * *

§ 520.445c [Redesignated as § 520.443]

■ 6. Redesignate § 520.445c as § 520.443.

■ 7. Amend newly redesignated § 520.443 as follows:

■ a. Revise paragraphs (a) and (b);

■ b. Remove paragraph (d);

■ c. Redesignate paragraph (e) as paragraph (d); and

■ d. Revise the heading for newly redesignated paragraph (d) introductory text.

The revisions read as follows:

§ 520.443 Chlortetracycline tablets and boluses.

(a) *Specifications.* Each tablet/bolus contains 25, 250, or 500 milligrams (mg) chlortetracycline hydrochloride.

(b) *Sponsor.* See No. 000010 in § 510.600(c) of this chapter.

* * * * *

(d) *Conditions of use in calves*—* * *

* * * * *

Dated: August 4, 2011.

Elizabeth Rettie,

Deputy Director, Office of New Animal Drug Evaluation, Center for Veterinary Medicine.

[FR Doc. 2011–20404 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF THE TREASURY

Office of the Secretary

31 CFR Part 10

[TD 9527]

RIN 1545–BH01

Regulations Governing Practice Before the Internal Revenue Service; Correction

AGENCY: Office of the Secretary, Treasury.

ACTION: Correcting amendment.

SUMMARY: This document contains amendments to the regulations governing practice before the Internal Revenue Service to correct errors in final regulations (TD 9527) that were published in the **Federal Register** on Friday, June 3, 2011. The regulations affect individuals who practice before the IRS and providers of continuing education programs. The regulations modify the rules governing of practice before the IRS and the standards with respect to tax returns.

DATES: This correction is effective on August 11, 2011 and is applicable beginning August 2, 2011.

FOR FURTHER INFORMATION CONTACT: Matthew D. Lucey, (202) 622–4940 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Background

The final regulation (TD 9527) that is the subject of this correction is under section 330 of Title 31 of the United States Code.

Need for Correction

As published on June 3, 2011, at 76 FR 32286, TD 9527 contains errors that may prove to be misleading and is in need of clarification.

List of Subjects in 31 CFR Part 10

Accountants, Administrative practice and procedure, Lawyers, Reporting and recordkeeping requirements, Taxes.

Correction of Publication

Accordingly, 31 CFR part 10 is corrected by making the following correcting amendments:

PART 10—PRACTICE BEFORE THE INTERNAL REVENUE SERVICE

■ **Paragraph 1.** The authority citation for part 31 continues to read in part as follows:

Authority: Sec. 3, 23 Stat. 258, secs. 2–12, 60 Stat. 237 et seq.; 5 U.S.C. 301, 500, 551–559; 31 U.S.C. 321; 31 U.S.C. 330; Reorg. Plan No. 26 of 1950, 15 FR 4935, 64 Stat. 1280, 3 CFR, 1949–1953 Comp., p. 1017.

■ **Par. 2.** Section 10.5 is amended by revising paragraph (g) to read as follows:

§ 10.5 Application to become an enrolled agent, enrolled retirement plan agent, or registered tax return preparer.

* * * * *

(g) *Effective/applicability date.* This section is applicable to applications received on or after August 2, 2011.

■ **Par. 3.** Section 10.60 is amended by revising paragraphs (a) and (b) to read as follows:

§ 10.60 Institution of proceeding.

(a) Whenever it is determined that a practitioner (or employer, firm or other entity, if applicable) violated any provision of the laws governing practice before the Internal Revenue Service or the regulations in this part, the practitioner may be reprimanded or, in accordance with § 10.62, subject to a proceeding for sanctions described in § 10.50.

(b) Whenever a penalty has been assessed against an appraiser under the Internal Revenue Code and an appropriate officer or employee in an office established to enforce this part determines that the appraiser acted willfully, recklessly, or through gross incompetence with respect to the proscribed conduct, the appraiser may be reprimanded or, in accordance with § 10.62, subject to a proceeding for disqualification. A proceeding for disqualification of an appraiser is instituted by the filing of a complaint, the contents of which are more fully described in § 10.62.

* * * * *

■ **Par. 4.** Section 10.69 is amended by revising paragraph (a) to read as follows:

§ 10.69 Representation; ex parte communication.

(a) *Representation.* (1) The Internal Revenue Service may be represented in proceedings under this part by an attorney or other employee of the Internal Revenue Service. An attorney or an employee of the Internal Revenue Service representing the Internal Revenue Service in a proceeding under this part may sign the complaint or any document required to be filed in the proceeding on behalf of the Internal Revenue Service.

(2) A respondent may appear in person, be represented by a practitioner, or be represented by an attorney who has not filed a declaration with the Internal Revenue Service pursuant to § 10.3. A practitioner or an attorney representing a respondent or proposed respondent may sign the answer or any document required to be filed in the proceeding on behalf of the respondent.

* * * * *

■ **Par. 5.** Section 10.90 is amended by revising paragraph (a)(6)(i) to read as follows:

§ 10.90 Records.

(a) * * *

(6) * * *

(i) Who have obtained a qualifying continuing education provider number; and

* * * * *

Treena V. Garrett,

Federal Register Liaison, Publications and Regulations Branch, Legal Processing Division, Associate Chief Counsel, Procedure and Administration.

[FR Doc. 2011–20380 Filed 8–10–11; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 159

[DOD–2008–OS–0125/RIN 0790–AI38]

Private Security Contractors (PSCs) Operating in Contingency Operations, Combat Operations or Other Significant Military Operations

AGENCY: Office of the Under Secretary of Defense for Acquisition, Technology, and Logistics, DoD.

ACTION: Final rule.

SUMMARY: This Rule establishes policy, assigns responsibilities and provides procedures for the regulation of the selection, accountability, training, equipping, and conduct of personnel performing private security functions under a covered contract during contingency operations, combat operations or other significant military operations. It also assigns responsibilities and establishes procedures for incident reporting, use of and accountability for equipment, rules for the use of force, and a process for administrative action or the removal, as appropriate, of PSCs and PSC personnel. For the Department of Defense, this Rule supplements DoD Instruction 3020.41, ''Contractor Personnel Authorized to Accompany the U.S. Armed Forces,'' which provides guidance for all DoD contractors operating in contingency operations.

This Rule was published as an Interim Final Rule on July 17, 2009 because there was insufficient policy and guidance regulating the actions of DoD and other governmental PSCs and their

movements in operational areas. This Rule ensures compliance with laws and regulations pertaining to Inherently Governmental functions, and ensures proper performance by armed contractors.

DATES: *Effective Date:* This rule is effective September 12, 2011.

FOR FURTHER INFORMATION CONTACT: Chris Mayer, Director, Armed Contingency Contractor Policy and Programs, Office of the Deputy Assistant Secretary of Defense (Program Support), (571) 232–2509.

SUPPLEMENTARY INFORMATION: The publication of this Rule is required to meet the mandate of Section 862 of the 2008 National Defense Authorization Act (NDAA), as amended by Section 813(b) of the 2010 NDAA and Section 832 of the 2011 NDAA. DoD has determined that the updates implementing Section 832 of the 2011 NDAA do not require additional public comment. These updates are in direct compliance with current statute, do not set a precedent in updating the interim final, and any delay in implementing these updates would be detrimental to U.S. security.

Background

This Final Rule [1] is required to meet the mandate of Section 862 of the FY 2008 NDAA, as amended, which lays out two requirements:

(i) That the Secretary of Defense, in coordination with the Secretary of State, shall prescribe regulations on the selection, training, equipping, and conduct of personnel performing private security functions under a covered contract in an area of combat operations or other significant military operations; and

(ii) That the FAR shall be revised to require the insertion into each covered contract (or, in the case of a task order, the contract under which the task order is issued) of a contract clause addressing the selection, training, equipping, and conduct of personnel performing private security functions under such contract.

This Final Rule meets requirement (i). There will be a separate and subsequent **Federal Register** action to meet requirement (ii) to update the FAR. On July 17, 2009, an Interim Final Rule (32 CFR Part 159 DOD–2008–OS–125/RIN 0790–AI38) was published and public comments were solicited. At the end of the comment period, we received comments from 9 respondents, including the American Bar Association, IPOA, NGO groups and members of the public. These comments are discussed below by topic.

[1] Nothing in this Final Rule is intended to reflect the views of the DoD or the United States regarding the merits of any claim or defense that may be asserted by a private party in any pending or future litigation or disputes.

Comment: Extent of Delegation of Implementation Authority to Each Geographic Combatant Commander

Response: We believe that it is appropriate for DoD to provide the Geographic Combatant Commanders with the requirements to be included in their respective guidance and procedures. Situations change significantly from one geographic region to another. The Geographic Combatant Commanders (GCC) must have the flexibility to apply the overarching policy, tailoring their guidance and procedures as necessary to meet the particular circumstances within their respective areas of responsibility at any particular time. This is consistent with the approach that we are currently taking in the CENTCOM Area Of Responsibility (AOR) without significant issue.

We do not believe that differing or conflicting regulations will be adopted within a single AOR. The GCC will establish the overarching guidance and Subordinate Commanders (down to Joint Task Force level) will develop implementing instructions. Specific requirements will be made available to Private Security Contractors through the GCC Web site.

Comment: Absence of Department-Wide Guidance

Response: We believe that a de-centralized approach is the most appropriate way to implement the requirements of Section 862 of the FY08 NDAA. There is sufficient uniformity of guidance provided through policy, including this Rule and existing acquisition regulations. The intent of the policy is that all PSC personnel operating within the designated area are required to have the required training, not only those who are deploying. A FAR case has been opened to incorporate the required revisions based upon the publication of this Final Rule.

Comment: Lack of Uniformity Across Organizations

Response: Following publication of this Final Rule, these requirements will be added to the FAR and DFARS and subsequently incorporated into appropriate contracts. This will provide a basis for the management of PSC compliance.

Comment: Chief of Mission Should Be Required to Opt Out of DoD PSC Processes

Response: We believe that the arrangement set out in Section 159.4(c) is appropriate and meets the congressional intent of a consistent approach towards PSCs operating in combat operations or other significant military operations, across USG agencies.

Comment: Any Procedures or Guidance Issued Under the Requirements of This Rule Should be Subject to an Appropriate Rule-Making with an Adequate Opportunity for Public Comment

Response: The relevant provisions of this Final Rule will be implemented through military regulations and orders, in accordance with existing procedures.

Comment: The Rule is Not Integrated with Standard Contracting Processes

Response: The requirements associated with GCC guidance and procedures will be included in any solicitations and therefore potential bidders will be aware of GCC specific procedures prior to submitting their proposals. AOR specific procedures such as training requirements are required to be placed on GCC Web sites immediately after a declared contingency so that the requirements can get into the appropriate contracts as soon as possible.

Comment: The Rule Should Fully Explain How DoD Determines a PSC Law of War Status

Response: It is not the role of the Rule to make statements regarding international law. Department Of Defense Instruction 3020.41, the overarching Defense policy document for this Rule, provides in paragraph 6.1.1 that:

> Under applicable law, contractors may support military operations as civilians accompanying the force, so long as such personnel have been designated as such by the force they accompany and are provided with an appropriate identification card under the provisions of the 1949 Geneva Convention Relative to the Treatment of Prisoners of War (GPW) (reference (j)). If captured during armed conflict, contingency contractor personnel accompanying the force are entitled to prisoner of war status.

The comments regarding direct participation in hostilities are unsupportable. There is no agreement within the international community or among recognized authorities in international humanitarian law (LOAC) on a universally applicable definition for ‘‘Direct Participation in Hostilities.’’

(Public address by Dr. Jakob Kellenberger, President, International Committee of the Red Cross, 11 September 2009.) Again, contracting regulations are not the place to define terms that are not yet defined under international law. The Rule specifies that command rules for the use of force will be consistent with Chairman of the Joint Chiefs of Staff Instruction 3121.01B. This will provide commonality regarding the Rules for the Use of Force (RUF) but with the flexibility for commands to interpret it in accordance with local, and sometimes transitory, circumstances.

Comment: The Rule may benefit from additional guidance on inter-agency cooperation

Response: Interagency coordination is essential to successful contingency planning. The Rule, as written supports flexible, agile, and focused contingency planning and DoD, DoS and USAID believe the rule provides sufficient strategic direction for interagency coordination relative to PSC oversight and conduct. DoD disagrees with the respondent's assertion that ''many coordination issues will be common across AORs.'' Some may, many more may not. The flexibility to adapt procedures to local circumstances is essential. As the same respondent notes in this same section, ''guidance and procedures in the Iraq Memorandum of Agreement (MOA) are not easily transferrable to contingency operations outside of Iraq.'' The MOA between DoD and DoS in place in Iraq has proven to be extremely successful and serves as a good example of interagency coordination. It was referenced in the IFR as an example or point of departure for developing GCC guidance and procedures. However, to avoid confusion, in the Final Rule we have removed the last sentence in Section 159.6(d) which references the MOA. DoD, DoS and USAID recognize that some PSC or PSC personnel activities may require coordination with other Federal agency partners who contract for private security services.

Comment: Confusion about Geographic Combatant Commander Delegation Authority to Subordinate Commander

Response: Geographic combatant commands themselves do not follow a uniform organizational structure and commanders are free to assign different responsibilities to the most appropriate components of their staffs. The language in the Final Rule has been changed to provide more specificity as to the subordinate level to which GCCs can delegate responsibility for implementation. Through the Rule, the phrase ''Subordinate Commander'' has been replaced with ''sub unified commanders or combined/joint task force commanders''.

Comment: The rule needs to include reference to existing powers of removal of a PSC and personnel

Response: Such language is unnecessary in so far as it is already addressed in our existing regulations. Section 862(b)(3) of the 2008 NDAA as amended includes the following language: ''NONCOMPLIANCE OF PERSONNEL WITH CLAUSE—The contracting officer for a covered contract may direct the contractor, at its own expense, to remove or replace any personnel performing private security functions in an area of combat operations or other significant military operations who violate or fail to comply with applicable requirements of the clause required by this subsection. If the violation or failure to comply is a gross violation or failure or is repeated, the contract may be terminated for default.'' Incorporation of this statutory language will be considered in the DFARS case implementing Section 862.

Comment: The rule fails to address subcontractors providing security for the prime contractor

Response: The definition of ''covered contract'' has been revised in the Rule to cover contracts for the performance of services and/or the delivery of supplies. Further, we will ensure that regulatory guidance developed subsequent to the publication of this Rule makes clear that subcontractors providing security for prime contractors must comply.

Comment: Recommend application of the rule to PSCs working under contract to the DoD whether domestically or internationally

Response: As required by Section 862 of the 2008 NDAA, as amended, this Rule applies to PSCs working for any U.S. Government agency in an area of combat operations or other significant military operations. It also applies to PSCs working for DoD in contingency operations outside the United States. The arrangements for PSC employment in the United States are outside the scope of this Rule.

Comment: Section 159.4(a) ''Consistent with the requirement of paragraph (a)(2) * * *'' should include at the end of the section, ''Coordination shall encompass the contemplated use of PSC personnel during the planning stages of contingency operations so to allow guidance to be developed under parts (b) and (c) herein and promulgate under 159.5 in a timely manner that is appropriate for the needs of the contingency operation''

Response: The language has been revised in the Final Rule.

Comment: Section 159.6(a)(i) ''Contain at a minimum procedures to implement the following process * * *'' should include, ''That the Secretary of Defense, in coordination with the Secretary of State, shall prescribe regulations on the selection, training, equipping, and conduct of personnel performing private security functions under a covered contract in an area of combat operations''

Response: We believe that the current wording is correct, as it reflects our intent.

Comment: Section 159.6(a)(ii) ''PSC verification that PSCs meet all the legal, training, and qualification requirements * * *'' should include ''That the FAR shall be revised to require the insertion into each covered contract of a contract clause; addressing the selection, training, equipping and conduct of personnel performing private security functions under such a contract''

Response: A FAR clause will be drafted to incorporate all of the requirements of this Rule.

Comment: Section 159.6(a)(v) ''Reporting alleged criminal activity and other incidents involving PSCs or PSC personnel by another company or any other personnel. All incidents shall be reported and documented.'' These reporting requirements are already required

Response: Many of the requirements in this rule are already in effect in the CENTCOM AOR. With this Rule, we are establishing the requirements for all Geographic Combatant Commanders and Chiefs of Mission in order to extend guidance and procedures globally and to the wider interagency community.

Comment: Questions of the propriety of having PSCs represent the U.S. in contingency operations relative to the U.S. Constitution and the Anti Pinkerton Act

Response: The DoD's use of contractors, including private security contractors, is entirely consistent with existing U.S. Government policy on inherently governmental functions. We are guided by four main documents when determining whether an activity or function is inherently governmental: DoD Instruction 1100.22 ''Policy and Procedures for Determining Workforce Mix''; the Federal Acquisition Regulations (FAR); the Performance of Commercial Activities and the Federal Activities Inventory Reform Act, or FAIR Act, of 1998; and, Office of Management and Budget (OMB) Policy Letter 92–1, issued in 1992. The DoD recognizes that there are specific security functions that are inherently governmental and cannot be contracted. The DoD does not contract those functions, but there are other security functions that are appropriate to contract. The DoD, the Government Accountability Office (GAO), the Office of Management and Budget (OMB), the Congressional Budget Office (CBO), and the Congressional Research Service (CRS) have continuously reviewed the use of PSCs, the potential for their performance of inherently governmental functions, and the appropriateness and manner in which they are employed.

Comment: Opposition to the use of mercenaries in the U.S. Department of Defense

Response: The DoD does not use mercenaries. Article 47 of Additional Protocol I to Geneva Conventions provides an internationally accepted definition of mercenaries. The elements of that definition clearly exclude PSCs under contract to DoD. Private security contractors do not perform military functions, but rather, they carry out functions similar to those performed by security guards in the United States and elsewhere. We agree that the behavior of PSCs may affect the national security goals of the U.S. and for this reason we have published guidance on the selection, oversight, and management of private security contractors operating in contingency operations.

Comment: DoD personnel do not want PSCs in a combat situation

Response: The primary role of the armed forces is combat: to close with and destroy enemy armed forces through firepower, maneuver, and shock action. Defense of military personnel and activities against organized attack is a military responsibility. DoD allocates military personnel to these high priority combat and other critical combat support missions. Private Security Companies contracted by the U.S. government protect personnel, facilities and activities against criminal activity, including individual acts of terrorism. They are specifically prohibited from engaging in combat (offensive) operations and certain security functions. DoD PSCs have performed well and are very important to our mission accomplishment in the CENTCOM area of responsibility.

Comment: PSCs should receive Veteran's Affairs benefits for injuries sustained while protecting the country

Response: PSCs and other contractors employed by the U.S. government who perform work outside of the United States are covered by the Longshore and Harbor Workers' Compensation Act (LHWCA). The LHWCA provides disability compensation and medical benefits to employees and death benefits to eligible survivors of employees of U.S. government contractors who perform work overseas.

The Defense Base Act is an extension of the LHWCA. The Defense Base Act covers the following employment activities: (1) Work for private employers on U.S. military bases or on any lands used by the U.S. for military purposes outside of the United States, including those in U.S. Territories and possessions; (2) Work on public work contracts with any U.S. government agency, including construction and service contracts in connection with national defense or with war activities outside the United States; (3) Work on contracts approved and funded by the U.S. under the Foreign Assistance Act, which among other things provides for cash sale of military equipment, materials, and services to its allies, if the contract is performed outside of the United States; or (4) Work for American employers providing welfare or similar services outside the United States for the benefit of the Armed Services, *e.g.* the United Service Organizations (USO). If any one of the above criteria is met, all employees engaged in such employment, regardless of nationality (including U.S. citizens and residents, host country nationals (local hires), and third country nationals (individuals hired from another country to work in the host country)), are covered under the Act.

Comment: Requirements jeopardize NGO security posture

Response: This Rule applies only to personnel performing private security functions under a covered contract. A covered contract is defined by Section 864(a)(3) of the FY 2008 NDAA, as amended by Section 813(b) of the FY 2010 NDAA.

Comment: USAID involvement is not evident

Response: USAID has been actively involved in various working groups implementing the Interim Final Rule and developing the Final Rule.

Comment: PSC rules should be consistent with the spirit and intent of Guidelines for Relations between U.S. Armed Forces and Non-Governmental Humanitarian Agencies in Hostile or Potentially Hostile Environments

Response: The purpose of publishing the IFR in the **Federal Register** was to obtain the comments of affected agencies, NGOs, contractors and the public. The respondent was not specific about any perceived conflicts that needed to be addressed in the PSC rule, and should work with their USAID and other agency counterparts to provide specific inputs on implementing the Final Rule.

Comment: PSC rules should not apply to unarmed guard forces

Response: We believe that the current language is correct. When contractors providing guard services are not armed, those aspects of the rule which are specific to armed contractors (*i.e.* arming procedures) are not relevant.

Comment: Procedures associated with PSC rules must be adapted to contexts in which NGOs have long-standing programs or minor amounts of U.S. Government funding

Response: This Rule applies only to personnel performing private security functions under a covered contract. A covered contract is defined by Section 864(a)(3) of the FY 2008 NDAA, as amended by Section 813(b) of the FY 2010 NDAA.

Comment: SPOT's use for intelligence gathering and vetting is unclear

Response: The Synchronized Pre-deployment and Operational Tracker (SPOT) is a Web-based database which is used to gain visibility over contracts and contractors supporting U.S. Government agencies during contingency operations. The SPOT system serves multiple purposes; it allows contractors to request and receive specific logistics support such as meals, housing, transportation, medical support while working in-country; it provides Contracting Officer Representatives and Grants Officer Representatives with information on what contractor and grantee employees are working in what locations which makes approval of invoices and inspection of work easier; it allows Contracting Officer Representatives, Grants Officer Representatives, and other personnel to review the credentials of individuals requesting the authority to carry weapons (either government furnished or contractor acquired) in the performance of a U.S. government contract or grant; it allows agencies to report to Congress and other oversight organizations on the size of contractor and grantee presence in areas of combat operations or other significant military operations. Congress believes the system is necessary. Section 861 of FY 2008 NDAA provides that the Secretary of Defense, the Secretary of State, and the Administrator of USAID must agree to adopt a common database for contractors in Iraq and Afghanistan. SPOT is not used for intelligence gathering or vetting of personnel. Background checks of PSCs are conducted by the contractor and validated by the contracting officer. This validation is only annotated in SPOT.

Comment: Applicable guidelines must be effectively disseminated to NGOs

Response: Contracting Officers and Grants Officers will remain the primary point of contact for contractors and grantees on issues affecting performance. Rules impacting contractors across multiple agencies will be promulgated via the FAR with appropriate opportunities for contractor and public comment during the rulemaking process. Rules impacting grantees across multiple agencies will be promulgated by the Office of Management and Budget (OMB) Office of Federal Financial Management (OFFM) as part of its responsibility to issue government-wide grants policy. The DoD will ensure that a single location, readily accessible to both contractors and grantees, exists for the publication and maintenance of all guidance relating to PSC rules. The Department of State and USAID will provide any agency unique implementing guidance to DoD for publication on this same Web site.

Areas for Clarification and Definitions

Comment: ''Private Security Functions'' needs to be better defined

Response: The term ''private security functions'' is defined by section 864 of the FY 2008 NDAA; the IFR used this definition. The Rule provides requirements for the management and oversight of companies contracted to perform private security functions and certain employees who may be required to carry and use arms in the performance of their duties. Companies and their personnel contracted to provide training, maintenance, or other support functions that are not required to carry a weapon in the performance of their duties are not addressed by this Rule. For clarification, in the Final Rule we have added ''in accordance with the terms of their contract''.

Comment: Enforcement and liability pending adoption of FAR clauses

Response: A FAR case has been opened to incorporate the required revisions based upon the publication of this Rule.

Comment: The Rule should address foreseeable issue concerning host nation law

Response: The Geographic Combatant Commander has legal and political staffs capable of addressing the concerns expressed in this comment.

Comment: Obligations of non-PSC prime contractors

Response: The definition of ''covered contract'' has been reworded to cover contracts for the performance of services and/or the delivery of supplies.

Comment: IFR applicability to contingency operations in the U.S. and distinction between ''combat operations'' and ''contingency operations''

Response: The Rule does not apply to operations within the United States. We have clarified this in the definition of ''covered contract.''

Comment: Applicability to foreign actors

Response: When applicable conditions are met, the Rule covers all companies and personnel providing private security functions, regardless of the country of registration of the company or national origin of its employees. We believe that this is already made clear by sections 159.2 (b)(1) and (2) which state the policy prescription. The Rule applies to government entities and prescribes policies for the oversight and management of PSCs and PSC personnel. The clause in section 159.2 (2)(a)(2) starting with ''specifically'' describes the conditions under which this part would apply beyond DoD, to DoS and other Federal agencies. The acquisition regulations, rather than this rule, will serve as the implementing mechanisms for PSC companies.

Comment: Further define intelligence operations

Response: This language implements Section 862 (d) of the FY 2008 NDAA.

Comment: ''Active non-lethal countermeasure'' would benefit from a clear definition and examples

Response: The following clarification has been added to the Rule: ''Active non-lethal systems include laser optical distracters, acoustic hailing devices, electro-muscular TASER guns, blunt-trauma devices like rubber balls and sponge grenades, and a variety of riot-control agents and delivery systems.''

Comment: Definition of Contingency Operation is a slight variation of the definition of contingency operation in FAR 2.101

Response: The definition in the Rule has been updated; it is taken verbatim from U.S. Code Title 10, 101(a)(13).

Comment: Definition of Covered Contract excludes temporary arrangements outside of DoD for private security functions when contracted for by a non-DoD contractor or a grantee

Response: The genesis for this provision was a USAID concern that development projects undertaken by USAID may engage local personnel as security on an ad hoc basis, and that such arrangements should be excluded from complying with the requirements of this regulation. These arrangements cannot realistically be regulated in the same manner as traditional contracts.

Comment: Regarding the Standing rules on the use of force consider stating: ''Issue written authorization to the PSC identifying individual PSC personnel who are authorized to be armed. Rules for the Use of Force shall be included with the written authorization, if not previously provided to the contractor in the solicitation or during the course of contract administration. Rules for the Use of Force shall conform to the guidance in the Chairman of the Joint Chiefs of Staff Instruction 3121.01B, ''Standing Rules of Engagement/ Standing Rules for the Use of Force for U.S. Forces''

Response: Agreed. The Rule has been revised to reflect the proposed change in wording.

Regulatory Procedures

Executive Order 12866, ''Regulatory Planning and Review'' and Executive Order 13563, ''Improving Regulation and Regulatory Review''

It has been certified that 32 CFR part 159 does not:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy; a section of the economy;

productivity; competition; jobs; the environment; public health or safety; or State, local, or Tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another Agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in these Executive Orders.

Public Law 104–121, ''Congressional Review Act'' (5 U.S.C. 801)

It has been determined that 32 CFR part 159 is not a ''major'' rule under 5 U.S.C. 801, enacted by Pub. L. 104–121, because it will not result in an annual effect on the economy of $100 million or more; a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.

Section 202, Public Law 104–4, ''Unfunded Mandates Reform Act''

It has been certified that 32 CFR part 159 does not contain a Federal mandate that may result in expenditure by State, local and Tribal governments, in aggregate, or by the private sector, of $100 million or more in any one year.

Public Law 96–354, ''Regulatory Flexibility Act'' (5 U.S.C. 601)

It has been certified that 32 CFR part 159 is not subject to the Regulatory Flexibility Act (5 U.S.C. 601) because it would not, if promulgated, have a significant economic impact on a substantial number of small entities. This rule will apply only to a specific sector of defense industry and a limited number of small entities.

Public Law 96–511, ''Paperwork Reduction Act'' (44 U.S.C. Chapter 35)

It has been certified that 32 CFR part 159 does impose reporting or recordkeeping requirements under the Paperwork Reduction Act of 1995. These requirements have been approved by OMB and assigned OMB Control Numbers 0704–0460, ''Synchronized Predeployment and Operational Tracker (SPOT) System'' and 0704–0461, ''Qualification to Possess Firearms or Ammunition.''

Executive Order 13132, ''Federalism''

It has been certified that 32 CFR part 159 does not have federalism implications, as set forth in Executive Order 13132. This rule does not have substantial direct effects on:

(1) The States;

(2) The relationship between the National Government and the States; or

(3) The distribution of power and responsibilities among the various levels of Government.

List of Subjects in 32 CFR Part 159

Contracts, Security measures.

Accordingly, the interim rule amending 32 CFR part 159 which was published at 74 FR 34691 on July 17, 2009, is adopted as a final rule with the following change. Part 159 is revised to read as follows:

PART 159—PRIVATE SECURITY CONTRACTORS OPERATING IN CONTINGENCY OPERATIONS

Authority: Pub. L. 110–181; Pub. L. 110–417.

§ 159.1 Purpose.

This part establishes policy, assigns responsibilities and provides procedures for the regulation of the selection, accountability, training, equipping, and conduct of personnel performing private security functions under a covered contract. It also assigns responsibilities and establishes procedures for incident reporting, use of and accountability for equipment, rules for the use of force, and a process for administrative action or the removal, as appropriate, of PSCs and PSC personnel.

§ 159.2 Applicability and scope.

This part:

(a) Applies to:

(1) The Office of the Secretary of Defense, the Military Departments, the Office of the Chairman of the Joint Chiefs of Staff and the Joint Staff, the Combatant Commands, the Office of the Inspector General of the Department of Defense, the Defense Agencies, the DoD Field Activities, and all other organizational entities in the Department of Defense (hereafter referred to as the ''DoD Components'').

(2) The Department of State and other U.S. Federal agencies insofar as it implements the requirements of section 862 of Public Law 110–181, as amended. Specifically, in areas of operations which require enhanced coordination of PSC and PSC personnel working for U.S. Government (U.S.G.) agencies, the Secretary of Defense may designate such areas as areas of combat operations or other significant military operations for the limited purposes of this part. In such an instance, the standards established in accordance with this part would, in coordination with the Secretary of State, expand from covering only DoD PSCs and PSC personnel to cover all U.S.G.-funded PSCs and PSC personnel operating in the designated area. The requirements of this part shall not apply to a nonprofit nongovernmental organization receiving grants or cooperative agreements for activities conducted within an area of other significant military operations if the Secretary of Defense and the Secretary of State agree that such organization may be exempted. An exemption may be granted by the agreement of the Secretaries under this paragraph on an organization-by-organization or area-by-area basis. Such an exemption may not be granted with respect to an area of combat operations.

(b) Prescribes policies applicable to all:

(1) DoD PSCs and PSC personnel performing private security functions during contingency operations outside the United States.

(2) USG-funded PSCs and PSC personnel performing private security functions in an area of combat operations or, with the agreement of the Secretary of State, other significant military operations as designated by the Secretary of Defense.

§ 159.3 Definitions.

Unless otherwise noted, these terms and their definitions are for the purpose of this part.

Area of combat operations. An area of operations designated as such by the Secretary of Defense for the purpose of this part, when enhanced coordination of PSCs working for U.S.G. agencies is required.

Contingency operation. A military operation that is either designated by the Secretary of Defense as a contingency operation or becomes a contingency operation as a matter of law (10 U.S.C. 101(a)(13)). It is a military operation that:

(1) Is designated by the Secretary of Defense as an operation in which members of the Armed Forces are or may become involved in military actions, operations, or hostilities against an enemy of the United States or against an opposing military force; or

(2) Results in the call or order to, or retention on, active duty of members of

the uniformed services under section 688, 12301(a), 12302, 12304, 12305, 12406, of 10 U.S.C., chapter 15 of 10 U.S.C. or any other provision of law during a war or during a national emergency declared by the President or Congress.

Contractor. The contractor, subcontractor, grantee, or other party carrying out the covered contract.

Covered contract. (1) A DoD contract for performance of services and/or delivery of supplies in an area of contingency operations outside the United States or a contract of a non-DoD Federal agency for performance of services and/or delivery of supplies in an area of combat operations or other significant military operations, as designated by the Secretary of Defense; a subcontract at any tier under such a contract; or a task order or delivery order issued under such a contract or subcontract.

(2) Also includes contracts or subcontracts funded under grants and sub-grants by a Federal agency for performance in an area of combat operations or other significant military operations as designated by the Secretary of Defense.

(3) Excludes temporary arrangements entered into by non-DoD contractors or grantees for the performance of private security functions by individual indigenous personnel not affiliated with a local or expatriate security company. Such arrangements must still be in compliance with local law.

Other significant military operations. For purposes of this part, the term 'other significant military operations' means activities, other than combat operations, as part of an overseas contingency operation that are carried out by United States Armed Forces in an uncontrolled or unpredictable high-threat environment where personnel performing security functions may be called upon to use deadly force.[1]

Private security functions. Activities engaged in by a contractor under a covered contract as follows:

(1) Guarding of personnel, facilities, designated sites, or property of a Federal agency, the contractor or subcontractor, or a third party.[2]

(2) Any other activity for which personnel are required to carry weapons in the performance of their duties in accordance with the terms of their contract. For the DoD, DoDI Instruction 3020.41, ''Contractor Personnel Authorized to Accompany the U.S. Armed Forces,'' [3] prescribes policies related to personnel allowed to carry weapons for self defense.

PSC. During contingency operations ''PSC'' means a company employed by the DoD performing private security functions under a covered contract. In a designated area of combat operations or other significant military operations, the term ''PSC'' expands to include all companies employed by U.S.G. agencies performing private security functions under a covered contract.

PSC personnel. Any individual performing private security functions under a covered contract.

§ 159.4 Policy.

(a) Consistent with the requirements of paragraph (a)(2) of section 862 of Public Law 110–181, the selection, training, equipping, and conduct of PSC personnel including the establishment of appropriate processes shall be coordinated between the DoD and the Department of State. Coordination shall encompass the contemplated use of PSC personnel during the planning stages of contingency operations so as to allow guidance to be developed under paragraphs (b) and (c) of this section and promulgated under section 159.5 of this part in a timely manner that is appropriate for the needs of the contingency operation.

(b) Geographic Combatant Commanders will provide tailored PSC guidance and procedures for the operational environment in their Area of Responsibility (AOR) in accordance with this part, the Federal Acquisition Regulation (FAR) [4] and the Defense Federal Acquisition Regulation Supplement (DFARS).[5]

(c) In a designated area of combat operations or other significant military operations, the relevant Chief of Mission will be responsible for developing and issuing implementing instructions for non-DoD PSCs and their personnel consistent with the standards set forth by the geographic Combatant Commander in accordance with paragraph (b) of this section. The Chief of Mission has the option to instruct non-DoD PSCs and their personnel to follow the guidance and procedures developed by the geographic Combatant Commander and/or a sub unified commander or joint force commander (JFC) where specifically authorized by the Combatant Commander to do so and notice of that authorization is provided to non-DoD agencies.

(d) The requirements of this part shall not apply to contracts entered into by elements of the intelligence community in support of intelligence activities.

§ 159.5 Responsibilities.

(a) The Deputy Assistant Secretary of Defense for Program Support, under the authority, direction, and control of the Assistant Secretary of Defense for Logistics and Materiel Readiness, shall monitor the registering, processing, and accounting of PSC personnel in an area of contingency operations.

(b) The Director, Defense Procurement and Acquisition Policy, under the authority, direction, and control of the Under Secretary of Defense for Acquisition, Technology and Logistics, shall ensure that the DFARS and (in consultation with the other members of the FAR Council) the FAR provide appropriate guidance and contract clauses consistent with this part and paragraph (b) of section 862 of Public Law 110–181.

(c) The Deputy Chief Management Officer of the Department of Defense shall direct the appropriate component to ensure that information systems effectively support the accountability and visibility of contracts, contractors, and specified equipment associated with private security functions.

(d) The Chairman of the Joint Chiefs of Staff shall ensure that joint doctrine is consistent with the principles established by DoD Directive 3020.49, ''Orchestrating, Synchronizing, and Integrating Program Management of Contingency Acquisition Planning and Its Operational Execution,'' [6] DoD Instruction 3020.41, ''Contractor Personnel Authorized to Accompany the U.S. Armed Forces,'' and this part.

(e) The geographic Combatant Commanders in whose AOR a contingency operation is occurring, and within which PSCs and PSC personnel perform under covered contracts, shall:

(1) Provide guidance and procedures, as necessary and consistent with the principles established by DoD Directive 3020.49, ''Orchestrating, Synchronizing, and Integrating Program Management of Contingency Acquisition Planning and Its Operational Execution,'' DoD Instruction 3020.41, ''Contractor

[1] With respect to an area of other significant military operations, the requirements of this part shall apply only upon agreement of the Secretary of Defense and the Secretary of State. Such an agreement of the Secretaries may be made only on an area-by-area basis. With respect to an area of combat operations, the requirements of this part shall always apply.

[2] Contractors performing private security functions are not authorized to perform inherently governmental functions. In this regard, they are limited to a defensive response to hostile acts or demonstrated hostile intent.

[3] Available at *http://www.dtic.mil/whs/directives/corres/pdf/302041p.pdf*.

[4] Published in Title 48 of the Code of Federal Regulations.

[5] Published in Title 48 of the Code of Federal Regulations.

[6] Available from *http://www.dtic.mil/whs/directives/corres/pdf/302040p.pdf*.

Personnel Authorized to Accompany the U.S. Armed Forces,'' [7] and this part, for the selection, training, accountability and equipping of such PSC personnel and the conduct of PSCs and PSC personnel within their AOR. Individual training and qualification standards shall meet, at a minimum, one of the Military Departments' established standards. Within a geographic combatant command, a sub unified commander or JFC shall be responsible for developing and issuing implementing procedures as warranted by the situation, operation, and environment, in consultation with the relevant Chief of Mission in designated areas of combat operations or other significant military operations.

(2) Through the Contracting Officer, ensure that PSC personnel acknowledge, through their PSC, their understanding and obligation to comply with the terms and conditions of their covered contracts.

(3) Issue written authorization to the PSC identifying individual PSC personnel who are authorized to be armed. Rules for the Use of Force shall be included with the written authorization, if not previously provided to the contractor in the solicitation or during the course of contract administration. Rules for the Use of Force shall conform to the guidance in the Chairman of the Joint Chiefs of Staff Instruction 3121.01B, ''Standing Rules of Engagement/Standing Rules for the Use of Force for U.S. Forces.'' Access by offerors and contractors to the rules for the use of force may be controlled in accordance with the terms of FAR 52.204–2 (Aug 1996), DFARS 252.204–7000 (Dec 1991), or both.[8]

(4) Ensure that the procedures, orders, directives and instructions prescribed in § 159.6(a) of this part are available through a single location (to include an Internet Web site, consistent with security considerations and requirements).

(f) The Heads of the DoD Components shall:

(1) Ensure that all private security-related requirement documents are in compliance with the procedures listed in § 159.6 of this part and the guidance and procedures issued by the geographic Combatant Command,

(2) Ensure private security-related contracts contain the appropriate clauses in accordance with the applicable FAR clause and include additional mission-specific requirements as appropriate.

§ 159.6 Procedures.

(a) *Standing Combatant Command Guidance and Procedures.* Each geographic Combatant Commander shall develop and publish guidance and procedures for PSCs and PSC personnel operating during a contingency operation within their AOR, consistent with applicable law; this part; applicable Military Department publications; and other applicable DoD issuances to include DoD Directive 3020.49, ''Orchestrating, Synchronizing, and Integrating Program Management of Contingency Acquisition Planning and Its Operational Execution,'' DFARS, DoD Directive 2311.01E, ''DoD Law of War Program,'' [9] DoD 5200.8–R, ''Physical Security Program,'' [10] CJCSI 3121.01B, ''Standing Rules of Engagement/Standing Rules for the Use of Force for U.S. Forces,'' and DoD Directive 5210.56, ''Use of Deadly Force and the Carrying of Firearms by DoD Personnel Engaged in Law Enforcement and Security Duties.'' [11] The guidance and procedures shall:

(1) Contain, at a minimum, procedures to implement the following processes, and identify the organization responsible for managing these processes:

(i) Registering, processing, accounting for and keeping appropriate records of PSCs and PSC personnel in accordance with DoD Instruction 3020.41, ''Contractor Personnel Authorized to Accompany the U.S. Armed Forces.''

(ii) PSC verification that PSC personnel meet all the legal, training, and qualification requirements for authorization to carry a weapon in accordance with the terms and conditions of their contract and host country law. Weapons accountability procedures will be established and approved prior to the weapons authorization.

(iii) Arming of PSC personnel. Requests for permission to arm PSC personnel shall be reviewed on a case-by-case basis by the appropriate Staff Judge Advocate to the geographic Combatant Commander (or a designee) to ensure there is a legal basis for approval. The request will then be approved or denied by the geographic Combatant Commander or a specifically identified designee, no lower than the flag officer level. Requests to arm non-DOD PSC personnel shall be reviewed and approved in accordance with § 159.4(c) of this part. Requests for permission to arm all PSC personnel shall include:

(A) A description of where PSC personnel will operate, the anticipated threat, and what property or personnel such personnel are intended to protect, if any.

(B) A description of how the movement of PSC personnel will be coordinated through areas of increased risk or planned or ongoing military operations, including how PSC personnel will be rapidly identified by members of the U.S. Armed Forces.

(C) A communication plan, to include a description of how relevant threat information will be shared between PSC personnel and U.S. military forces and how appropriate assistance will be provided to PSC personnel who become engaged in hostile situations. DoD contractors performing private security functions are only to be used in accordance with DoD Instruction 1100.22, ''Guidance for Determining Workforce Mix,'' [12] that is, they are limited to a defensive response to hostile acts or demonstrated hostile intent.

(D) Documentation of individual training covering weapons familiarization and qualification, rules for the use of force, limits on the use of force including whether defense of others is consistent with host nation Status of Forces Agreements or local law, the distinction between the rules of engagement applicable to military forces and the prescribed rules for the use of force that control the use of weapons by civilians, and the Law of Armed Conflict.

(E) Written acknowledgment by the PSC and its individual PSC personnel, after investigation of background of PSC personnel by the contractor, verifying such personnel are not prohibited under U.S. law to possess firearms.

(F) Written acknowledgment by the PSC and individual PSC personnel that:

(1) Inappropriate use of force by contractor personnel authorized to accompany the U.S. Armed Forces may subject such personnel to United States

[7] Available at *http://www.dtic.mil/whs/directives/corres/html/302041.htm*.

[8] CJCSI 3121.01B provides guidance on the standing rules of engagement (SROE) and establishes standing rules for the use of force (SRUF) for DOD operations worldwide. This document is classified secret. CJCSI 3121.01B is available via Secure Internet Protocol Router Network at *http://js.smil.mil.* If the requester is not an authorized user of the classified network, the requester should contact Joint Staff J–3 at 703–614–0425.

[9] Available at *http://www.dtic.mil/whs/directives/corres/html/231101.htm*.

[10] Available at *http://www.dtic.mil/whs/directives/corres/pdf/520008r.pdf*.

[11] Available at *http://www.dtic.mil/whs/directives/corres/html/521056.htm*.

[12] Available at *http://www.dtic.mil/whs/directives/corres/pdf/110022p.pdf*.

or host nation prosecution and civil liability.[13]

(2) Proof of authorization to be armed must be carried by each PSC personnel.

(3) PSC personnel may possess only U.S.G.-issued and/or -approved weapons and ammunition for which they have been qualified according to paragraph (a)(1)(iii)(E) of this section.

(4) PSC personnel were briefed about and understand limitations on the use of force.

(5) Authorization to possess weapons and ammunition may be revoked for non-compliance with established rules for the use of force.

(*6*) PSC personnel are prohibited from consuming alcoholic beverages or being under the influence of alcohol while armed.

(iv) Registration and identification in the Synchronized Predeployment and Operational Tracker (or its successor database) of armored vehicles, helicopters, and other vehicles operated by PSC personnel.

(v) Reporting alleged criminal activity or other incidents involving PSCs or PSC personnel by another company or any other person. All incidents involving the following shall be reported and documented:

(A) A weapon is discharged by an individual performing private security functions;

(B) An individual performing private security functions is killed or injured in the performance of their duties;

(C) A person other than an individual performing private security functions is killed or injured as a result of conduct by PSC personnel;

(D) Property is destroyed as a result of conduct by a PSC or PSC personnel;

(E) An individual performing private security functions has come under attack including in cases where a weapon is discharged against an individual performing private security functions or personnel performing such functions believe a weapon was so discharged; or

(F) Active, non-lethal counter-measures (other than the discharge of a weapon) are employed by PSC personnel in response to a perceived immediate threat in an incident that could significantly affect U.S. objectives with regard to the military mission or international relations. (Active non-lethal systems include laser optical distracters, acoustic hailing devices, electro-muscular TASER guns, blunt-trauma devices like rubber balls and sponge grenades, and a variety of riot-control agents and delivery systems).

(vi) The independent review and, if practicable, investigation of incidents reported pursuant to paragraphs (a)(1)(v)(A) through (a)(1)(v)(F) of this section and incidents of alleged misconduct by PSC personnel.

(vii) Identification of ultimate criminal jurisdiction and investigative responsibilities, where conduct of U.S.G.-funded PSCs or PSC personnel are in question, in accordance with applicable laws to include a recognition of investigative jurisdiction and coordination for joint investigations (*i.e.,* other U.S.G. agencies, host nation, or third country agencies), where the conduct of PSCs and PSC personnel is in question.

(viii) A mechanism by which a commander of a combatant command may request an action by which PSC personnel who are non-compliant with contract requirements are removed from the designated operational area.

(ix) Interagency coordination of administrative penalties or removal, as appropriate, of non-DoD PSC personnel who fail to comply with the terms and conditions of their contract, as they relate to this part.

(x) Implementation of the training requirements contained below in paragraph (a)(2)(ii) of this section.

(2) Specifically cover:

(i) Matters relating to authorized equipment, force protection, security, health, safety, and relations and interaction with locals in accordance with DoD Instruction 3020.41, ''Contractor Personnel Authorized to Accompany the U.S. Armed Forces.''

(ii) Predeployment training requirements addressing, at a minimum, the identification of resources and assistance available to PSC personnel as well as country information and cultural training, and guidance on working with host country nationals and military personnel.

(iii) Rules for the use of force and graduated force procedures.

(iv) Requirements and procedures for direction, control and the maintenance of communications with regard to the movement and coordination of PSCs and PSC personnel, including specifying interoperability requirements. These include coordinating with the Chief of Mission, as necessary, private security operations outside secure bases and U.S. diplomatic properties to include movement control procedures for all contractors, including PSC personnel.

(b) *Availability of Guidance and Procedures.* The geographic Combatant Commander shall ensure the guidance and procedures prescribed in paragraph (a) of this section are readily available and accessible by PSCs and their personnel (*e.g.,* on a Web page and/or through contract terms), consistent with security considerations and requirements.

(c) *Subordinate Guidance and Procedures.* A sub unified commander or JFC, in consultation with the Chief of Mission, will issue guidance and procedures implementing the standing combatant command publications specified in paragraph (a) of this section, consistent with the situation and operating environment.

(d) *Consultation and Coordination.* The Chief of Mission and the geographic Combatant Commander/sub unified commander or JFC shall make every effort to consult and coordinate responses to common threats and common concerns related to oversight of the conduct of U.S.G.-funded PSCs and their personnel.

Dated: August 3, 2011.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2011–20239 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

[13] This requirement is specific to arming procedures. Such written acknowledgement should not be construed to limit potential civil and criminal liability to conduct arising from ''the use of weapons.'' For example, PSC personnel could be held criminally liable for any conduct that would constitute a Federal offense (see MEJA, 18 U.S.C. 3261(a)).

DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 319

[Docket ID DOD–2011–OS–0022]

Privacy Act; Implementation

AGENCY: Defense Intelligence Agency, DoD.

ACTION: Direct final rule with request for comments.

SUMMARY: The Defense Intelligence Agency is deleting an exemption rule for LDIA 0275, ''DoD Hotline Referrals'' in its entirety. This direct final rule makes nonsubstantive changes to the Defense Intelligence Agency Privacy Program rules. These changes will allow the Department to transfer these records to another system of records LDIA 0271, ''Investigations and Complaints'' (July 19, 2006, 71 FR 41006). This will improve the efficiency and effectiveness of DoD's program by preserving the exempt status of the records when the purposes underlying the exemption are valid and necessary to protect the contents of the records. This rule is being published as a direct final rule as the Department of Defense does not

expect to receive any adverse comments, and so a proposed rule is unnecessary.

DATES: The rule will be effective on October 20, 2011 unless comments are received that would result in a contrary determination. Comments will be accepted on or before October 11, 2011.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods.

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Federal Docket management System Office, 1160 Defense Pentagon, Room 3C843, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ms. Theresa Lowery at (202) 231–1193.

SUPPLEMENTARY INFORMATION:

Direct Final Rule and Significant Adverse Comments

DoD has determined this rulemaking meets the criteria for a direct final rule because it involves nonsubstantive changes dealing with DoD's management of its Privacy Progams. DoD expects no opposition to the changes and no significant adverse comments. However, if DoD receives a significant adverse comment, the Department will withdraw this direct final rule by publishing a notice in the **Federal Register**. A significant adverse comment is one that explains: (1) Why the direct final rule is inappropriate, including challenges to the rule's underlying premise or approach; or (2) why the direct final rule will be ineffective or unacceptable without a change. In determining whether a comment necessitates withdrawal of this direct final rule, DoD will consider whether it warrants a substantive response in a notice and comment process.

Executive Order 12866, ''Regulatory Planning and Review'' and Executive Order 13563, ''Improving Regulation and Regulatory Review''

It has been determined that Privacy Act rules for the Department of Defense are not significant rules. The rules do not (1) have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy; a sector of the economy; productivity; competition; jobs; the environment; public health or safety; or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another Agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in these Executive orders.

Public Law 96–354, ''Regulatory Flexibility Act'' (5 U.S.C. Chapter 6)

It has been determined that Privacy Act rules for the Department of Defense do not have significant economic impact on a substantial number of small entities because they are concerned only with the administration of Privacy Act systems of records within the Department of Defense. Public Law 96–511, ''Paperwork Reduction Act'' (44 U.S.C. chapter 35).

It has been determined that Privacy Act rules for the Department of Defense impose no additional information collection requirements on the public under the Paperwork Reduction Act of 1995.

Section 202, Public Law 104–4, ''Unfunded Mandates Reform Act''

It has been determined that the Privacy Act rulemaking for the Department of Defense does not involve a Federal mandate that may result in the expenditure by State, local and tribal governments, in the aggregate, or by the private sector, of $100 million or more and that such rulemaking will not significantly or uniquely affect small governments.

Executive Order 13132, ''Federalism''

It has been determined that the Privacy Act rules for the Department of Defense do not have federalism implications. The rules do not have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government.

List of Subjects in 32 CFR Part 319

Privacy.

Accordingly, 32 CFR 319 is amended as follows:

PART 319—DEFENSE INTELLIGENCE AGENCY PRIVACY PROGRAM

■ 1. The authority citation for 32 CFR part 319 continues to read as follows:

Authority: Pub. L. 93–579, 5 U.S.C. 552a(f) and (k).

■ 2. In § 319.13 remove and reserve paragraph (d) to read as follows:

§ 319.13 Specific exemptions.

* * * * *

(d) [Reserved].

* * * * *

Dated: July 8, 2011.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2011–20238 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 319

[Docket ID DOD–2011–OS–0087]

Privacy Act; Implementation

AGENCY: Defense Intelligence Agency, DoD.

ACTION: Direct final rule with request for comments.

SUMMARY: The Defense Intelligence Agency (DIA) is adding a new exemption rule for LDIA 0900, entitled ''Accounts Receivable, Indebtedness and Claims'' to exempt those records that have been previously claimed for the records in another Privacy Act system of records. To the extent that copies of exempt records from those other systems of records are entered into these case records, DIA hereby claims the same exemptions for the records as claimed in the original primary system of records of which they are a part. This direct final rule makes nonsubstantive changes to the Defense Intelligence Agency Program rules. These changes will allow the Department to exempt records from certain portions of the Privacy Act. This will improve the efficiency and effectiveness of DoD's program by preserving the exempt status of the records when the purposes underlying the exemption for the original records are still valid and necessary to protect the contents of the records. This rule is being published as a direct final rule as the Department of Defense does not expect to receive any adverse comments, and so a proposed rule is unnecessary.

DATES: The rule will be effective on October 20, 2011 unless comments are received that would result in a contrary determination. Comments will be accepted on or before October 11, 2011.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods.

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Mail:* Federal Docket management System Office, 1160 Defense Pentagon, Room 3C843, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ms. Theresa Lowery at (202) 231–1193.

SUPPLEMENTARY INFORMATION:

Direct Final Rule and Significant Adverse Comments

DoD has determined this rulemaking meets the criteria for a direct final rule because it involves nonsubstantive changes dealing with DoD's management of its Privacy Progams. DoD expects no opposition to the changes and no significant adverse comments. However, if DoD receives a significant adverse comment, the Department will withdraw this direct final rule by publishing a notice in the **Federal Register**. A significant adverse comment is one that explains: (1) Why the direct final rule is inappropriate, including challenges to the rule's underlying premise or approach; or (2) why the direct final rule will be ineffective or unacceptable without a change. In determining whether a comment necessitates withdrawal of this direct final rule, DoD will consider whether it warrants a substantive response in a notice and comment process.

Executive Order 12866, ''Regulatory Planning and Review'' and Executive Order 13563, ''Improving Regulation and Regulatory Review''

It has been determined that Privacy Act rules for the Department of Defense are not significant rules. The rules do not (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy; a sector of the economy; productivity; competition; jobs; the environment; public health or safety; or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another Agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in these Executive orders.

Public Law 96–354, ''Regulatory Flexibility Act'' (5 U.S.C. Chapter 6)

It has been determined that Privacy Act rules for the Department of Defense do not have significant economic impact on a substantial number of small entities because they are concerned only with the administration of Privacy Act systems of records within the Department of Defense.

Public Law 96–511, ''Paperwork Reduction Act'' (44 U.S.C. Chapter 35)

It has been determined that Privacy Act rules for the Department of Defense impose no additional information collection requirements on the public under the Paperwork Reduction Act of 1995.

Section 202, Public Law 104–4, ''Unfunded Mandates Reform Act''

It has been determined that the Privacy Act rulemaking for the Department of Defense does not involve a Federal mandate that may result in the expenditure by State, local and tribal governments, in the aggregate, or by the private sector, of $100 million or more and that such rulemaking will not significantly or uniquely affect small governments.

Executive Order 13132, ''Federalism''

It has been determined that the Privacy Act rules for the Department of Defense do not have federalism implications. The rules do not have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government.

List of Subjects in 32 CFR Part 319

Specific exemptions, Privacy.

Accordingly, 32 CFR part 319 is amended to read as follows:

PART 319—DEFENSE INTELLIGENCE AGENCY PRIVACY PROGRAM

■ 1. The authority citation for 32 CFR part 319 continues to read as follows:

Authority: Pub. L. 93–579, 5 U.S.C. 552a(f) and (k).

■ 2. In § 319.13, add paragraph (i) to read as follows:

§ 319.13 Specific exemptions.

* * * * *

(i) *System identifier and name:* LDIA 0900, Accounts Receivable, Indebtedness and Claims.

(1) *Exemption:* During the course of accounts receivable, indebtedness or claims actions, exempt materials from other systems of records may in turn become part of the case record in this system. To the extent that copies of exempt records from those ''other'' systems of records are entered into this system, the DIA hereby claims the same exemptions for the records from those ''other'' systems that are entered into this system, as claimed for the original primary system of which they are a part.

(2) *Authority:* 5 U.S.C. 552a(k)(2) through (k)(7).

(3) *Reasons:* Records are only exempt from pertinent provisions of 5 U.S.C. 552a to the extent such provisions have been identified and an exemption claimed for the original record and the purposes underlying the exemption for the original record still pertain to the record which is now contained in this system of records. In general, the exemptions were claimed in order to protect properly classified information relating to national defense and foreign policy, to avoid interference during the conduct of criminal, civil, or administrative actions or investigations, to ensure protective services provided the President and others are not compromised, to protect the identity of confidential sources incident to Federal employment, military service, contract, and security clearance determinations, to preserve the confidentiality and integrity of Federal testing materials, and to safeguard evaluation materials used for military promotions when furnished by a confidential source. The exemption rule for the original records will identify the specific reasons why the records are exempt from specific provisions of 5 U.S.C. 552a.

Dated: July 8, 2011.

Patricia L. Toppings,

OSD Federal Register, Liaison Officer, Department of Defense.

[FR Doc. 2011–20245 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 323

[Docket ID DoD–2009–OS–0006]

Privacy Act; Implementation

AGENCY: Defense Logistics Agency, DoD.

ACTION: Direct final rule with request for comments.

SUMMARY: The Defense Logistics Agency (DLA) is updating the DLA Privacy Act Program Rules by updating the language of the (k)(2) exemption. The update of the exemption will more accurately describe the basis for exempting the records. The Privacy Act system of records notice, S500.20, entitled ''Defense Logistics Agency Criminal Incident Reporting System Records'', has already been published on June 8, 2009, in the **Federal Register**. This direct final rule makes nonsubstantive changes to the Defense Logistics Agency Privacy Program rules. These changes will allow the Department to exempt records from certain portions of the Privacy Act. This will improve the efficiency and effectiveness of DoD's program by preserving the exempt status of the records when the purposes underlying the exemption are valid and necessary to protect the contents of the records.This rule is being published as a direct final rule as the Department of Defense does not expect to receive any adverse comments, and so a proposed rule is unnecessary.

DATES: The rule will be effective on October 20, 2011 unless comments are received that would result in a contrary determination. Comments will be accepted on or before October 11, 2011.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods.

- *Federal eRulemaking Portal: http://www.regulations.gov.*

Follow the instructions for submitting comments.

- *Mail:* Federal Docket management System Office, 1160 Defense Pentagon, Room 3C843, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ms. Jody Sinkler at (703) 767–5045.

SUPPLEMENTARY INFORMATION:

Direct Final Rule and Significant Adverse Comments

DoD has determined this rulemaking meets the criteria for a direct final rule because it involves nonsubstantive changes dealing with DoD's management of its Privacy Progams. DoD expects no opposition to the changes and no significant adverse comments. However, if DoD receives a significant adverse comment, the Department will withdraw this direct final rule by publishing a notice in the **Federal Register**. A significant adverse comment is one that explains: (1) Why the direct final rule is inappropriate, including challenges to the rule's underlying premise or approach; or (2) why the direct final rule will be ineffective or unacceptable without a change. In determining whether a comment necessitates withdrawal of this direct final rule, DoD will consider whether it warrants a substantive response in a notice and comment process.

Executive Order 12866, ''Regulatory Planning and Review'' and Executive Order 13563, ''Improving Regulation and Regulatory Review''

It has been determined that Privacy Act rules for the Department of Defense are not significant rules. The rules do not (1) have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy; a sector of the economy; productivity; competition; jobs; the environment; public health or safety; or State, local, or Tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another Agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in these Executive orders.

Public Law 96–354, ''Regulatory Flexibility Act'' (5 U.S.C. Chapter 6)

It has been determined that Privacy Act rules for the Department of Defense do not have significant economic impact on a substantial number of small entities because they are concerned only with the administration of Privacy Act systems of records within the Department of Defense.

Public Law 96–511, ''Paperwork Reduction Act'' (44 U.S.C. Chapter 35)

It has been determined that Privacy Act rules for the Department of Defense impose no additional information collection requirements on the public under the Paperwork Reduction Act of 1995.

Section 202, Public Law 104–4, ''Unfunded Mandates Reform Act''

It has been determined that Privacy Act rules for the Department of Defense do not involve a Federal mandate that may result in the expenditure by State, local and Tribal governments, in the aggregate, or by the private sector, of $100 million or more and that such rulemaking will not significantly or uniquely affect small governments.

Executive Order 13132, ''Federalism''

It has been determined that Privacy Act rules for the Department of Defense do not have federalism implications. The rules do not have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government.

List of Subjects in 32 CFR Part 323

Privacy.

Accordingly, 32 CFR part 323 is amended as follows:

PART 323—DLA PRIVACY ACT PROGRAM

■ 1. The authority citation for 32 CFR part 323 continues to read as follows:

Authority: Pub. L. 93–579, 88 Stat. 1896 (5 U.S.C. 552a).

■ 2. Paragraph (b) of Appendix H to 32 CFR part 323 is revised to read as follows:

Appendix H to Part 23—DLA Exemption Rules

* * * * *

b. ID: S500.20 (Specific exemption).

1. SYSTEM NAME:

Defense Logistics Agency Criminal Incident Reporting System Records.

2. EXEMPTION:

(i) Parts of this system may be exempt pursuant to 5 U.S.C. 552a(k)(2) if the investigative material is compiled for law enforcement purposes. However, if an individual is denied any right, privilege, or benefit for which he would otherwise be entitled by Federal law or for which he would otherwise be eligible, as a result of the maintenance of such information, the individual will be provided access to such information except to the extent that disclosure would reveal the identity of a confidential source if the information is compiled and maintained by a component of the agency, which performs as its principle function any activity pertaining to the enforcement of criminal laws.

(ii) The specific sections of 5 U.S.C. 552a from which the system is to be exempted are 5 U.S.C. 552a(c)(3) and (c)(4), (d), (e)(1), (e)(2), (e)(3), (e)(4)(G), (H), and (I), (e)(5), (f), and (g).

3. AUTHORITY:

5 U.S.C. 552a(k)(2).

4. REASONS:

(i) From subsection (c)(3) because to grant access to an accounting of disclosures as required by the Privacy Act, including the date, nature, and purpose of each disclosure and the identity of the recipient, could alert the subject to the existence of the investigation or prosecutive interest by DLA or other agencies. This could seriously compromise case preparation by prematurely revealing its existence and nature; compromise or interfere with witnesses or make witnesses reluctant to cooperate; and lead to suppression, alteration, or destruction of evidence.

(ii) From subsections (c)(4), (d), and (f) because providing access to this information could result in the concealment, destruction or fabrication of evidence and jeopardize the safety and well being of informants, witnesses and their families, and law enforcement personnel and their families. Disclosure of this information could also reveal and render ineffectual investigative techniques, sources, and methods used by this component and could result in the invasion of privacy of individuals only incidentally related to an investigation. Investigatory material is exempt to the extent that the disclosure of such material would reveal the identity of a source who furnished the information to the Government under an express promise that the identity of the source would be held in confidence, or prior to September 27, 1975 under an implied promise that the identity of the source would be held in confidence. This exemption will protect the identities of certain sources that would be otherwise unwilling to provide information to the Government. The exemption of the individual's right of access to his/her records and the reasons therefore necessitate the exemptions of this system of records from the requirements of the other cited provisions.

(iii) From subsection (e)(1) because it is not always possible to detect the relevance or necessity of each piece of information in the early stages of an investigation. In some cases, it is only after the information is evaluated in light of other evidence that its relevance and necessity will be clear.

(iv) From subsection (e)(2) because collecting information to the fullest extent possible directly from the subject individual may or may not be practical in a criminal investigation.

(v) From subsection (e)(3) because supplying an individual with a form containing a Privacy Act Statement would tend to inhibit cooperation by many individuals involved in a criminal investigation. The effect would be somewhat adverse to established investigative methods and techniques.

(vi) From subsections (e)(4)(G), (H), and (I) because it will provide protection against notification of investigatory material which might alert a subject to the fact that an investigation of that individual is taking place, and the disclosure of which would weaken the on-going investigation, reveal investigatory techniques, and place confidential informants in jeopardy who furnished information under an express promise that the sources' identity would be held in confidence (or prior to the effective date of the Act, under an implied promise). In addition, this system of records is exempt from the access provisions of subsection (d).

(vii) From subsection (e)(5) because the requirement that records be maintained with attention to accuracy, relevance, timeliness, and completeness would unfairly hamper the investigative process. It is the nature of law enforcement for investigations to uncover the commission of illegal acts at diverse stages. It is frequently impossible to determine initially what information is accurate, relevant, timely, and least of all complete. With the passage of time, seemingly irrelevant or untimely information may acquire new significance as further investigation brings new details to light.

(viii) From subsection (f) because the agency's rules are inapplicable to those portions of the system that are exempt and would place the burden on the agency of either confirming or denying the existence of a record pertaining to a requesting individual might in itself provide an answer to that individual relating to an on-going investigation. The conduct of a successful investigation leading to the indictment of a criminal offender precludes the applicability of established agency rules relating to verification of record, disclosure of the record to the individual and record amendment procedures for this record system.

(ix) From subsection (g) because this system of records should be exempt to the extent that the civil remedies relate to provisions of 5 U.S.C. 552a from which this rule exempts the system.

* * * * *

Dated: July 8, 2011.

Patricia L. Toppings,

OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2011–20240 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2011–0696]

Drawbridge Operation Regulation; Grassy Sound Channel, Middle Township, NJ

AGENCY: Coast Guard, DHS.

ACTION: Notice of temporary deviation from regulations.

SUMMARY: The Commander, Fifth Coast Guard District, has issued a temporary deviation from the regulation governing the operation of the Grassy Sound/ Ocean Drive Bascule Bridge across the Grassy Sound Channel, mile 1.0, at Middle Township, NJ. The deviation is necessary to accommodate racers in ''The Wild Half'' half marathon. This deviation allows the bridge to remain in the closed position to ensure safe passage for the half marathon racers.

DATES: This deviation is effective from 7:45 a.m. through 11 a.m. on August 27, 2011.

ADDRESSES: Documents mentioned in this preamble as being available in the docket are part of docket USCG–2011–0696 and are available online by going to *http://www.regulations.gov,* inserting USCG–2011–0696 in the ''Keyword'' box and then clicking ''Search''. They are also available for inspection or copying at the Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or e-mail Lindsey Middleton, Coast Guard; telephone 757–398–6629, e-mail *Lindsey.R.Middleton@uscg.mil.* If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION: Cape May County Department of Public Works has requested a temporary deviation from the current operating regulations of the Grassy Sound/Ocean Drive Bascule Bridge across the Grassy Sound Channel, mile 1.0, at Middle Township, NJ. The route of ''The Wild Half'' half marathon crosses the bridge twice and the requested deviation is to accommodate the race participants. To facilitate this event, the draw of the bridge will be maintained in the closed-to-navigation position from 7:45 a.m. until 11 a.m. on Sunday August 27, 2011.

The vertical clearance for this bridge in the closed position is 15 feet at Mean High Water and unlimited in the open position. The operating regulations are set forth in 33 CFR 117.721 which states that during this time of year the bridge shall open on signal from 6 a.m. to 8 p.m.

Vessels that can pass through the bridge in the closed position may do so at any time. The Coast Guard will inform the waterway users of the closure through our Local and Broadcast Notices to Mariners to minimize any impact caused by the temporary deviation. The bridge will be able to open for emergencies. In the past 6 years there have been minimal openings for this bridge during the morning hours in August. Most vessel traffic consists of a few tugs and tows and recreational boaters. Vessels can use the Stone Harbor Bridge across the Great Channel as an alternate route to Hereford Inlet and the Atlantic Ocean.

In accordance with 33 CFR 117.35(e), the drawbridge must return to its regular operating schedule immediately at the end of the designated time period. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: August 2, 2011.

Waverly W. Gregory, Jr.,

Bridge Program Manager, By direction of the Commander, Fifth Coast Guard District.

[FR Doc. 2011–20374 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2011–0669]

Drawbridge Operation Regulation; New Jersey Intracoastal Waterway (NJICW); Atlantic City, NJ

AGENCY: Coast Guard, DHS.

ACTION: Notice of temporary deviation from regulations.

SUMMARY: The Commander, Fifth Coast Guard District, has issued a temporary deviation from the regulation governing the operation of the Route 30/Abescon Boulevard Bridge across Beach Thorofare, NJICW mile 67.2 and the US 40–322 (Albany Avenue) Bridge across Inside Thorofare, NJICW mile 70.0, both at Atlantic City, NJ. The deviation allows the bridges to limit the number of openings to accommodate heavy volumes of vehicular traffic due to the annual Air Show at Bader Field.

DATES: This deviation is effective from 10 a.m. through 8 p.m on August 17, 2011.

ADDRESSES: Documents mentioned in this preamble as being available in the docket are part of docket USCG–2011–0669 and are available online by going to *http://www.regulations.gov,* inserting USCG–2011–0669 in the ''Keyword'' box and then clicking ''Search''. They are also available for inspection or copying at the Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or e-mail Ms. Lindsey Middleton, Coast Guard; telephone 757–398–6629, e-mail *Lindsey.R.Middleton@uscg.mil.* If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION: The New Jersey Department of Transportation requested a temporary deviation from the current operating regulations of the Route 30/Abescon Boulevard Bridge across Beach Thorofare, NJICW mile 67.2 and the US 40–322 (Albany Avenue) Bridge across Inside Thorofare, NJICW mile 70.0, both at Atlantic City, NJ. The bridge opening changes and closures have been requested to ensure the safety of the heavy volumes of vehicular traffic that would be transiting over the bridges for the annual Air Show at Bader Field located within the city limits. Under this tempoarary deviation, both bridges will open every two hours on the hour starting at 10 a.m. and lasting until 4 p.m. followed by bridge closures from 4 p.m. until 8 p.m. on Wednesday, August 17, 2011.

The current operating regulation for the Route 30/Abescon Boulevard Bridge is outlined at 33 CFR 117.733(e) which requires that the bridge shall open on signal but only if at least four hours notice is given; except that from April 1 through October 31, from 7 a.m. to 11 p.m., the draw need only open on the hour. The vertical clearance for this bascule bridge is 20 feet above mean high water in the closed position and unlimited in the open position.

The current operating regulation for the US 40–322 (Albany Avenue Bridge) is outlined at 33 CFR 117.733(f)which requires that on the weekdays during this time of year, the bridge shall open on signal; except that from 11 p.m. to 7 a.m., the draw need only open if at least four hours of notice is given, from 9 a.m. to 4 p.m. and from 6 p.m. to 9 p.m., the draw need only open on the hour and half hour, and from 4 p.m. to 6 p.m., the draw need not open. The vertical clearance for this bascule bridge is 10 feet above mean high water in the closed position and unlimited in the open position.

The majority of the vessels that transit the bridges this time of year are recreational boats. Vessels able to pass through the bridges in the closed positions may do so at any time. Both bridges will be able to open for emergencies. The Atlantic Ocean is an alternate route for vessels unable to pass through the bridges in the closed positions. The Coast Guard will inform the users of the waterway through our Local and Broadcast Notices to Mariners of the closure period so that vessels can plan their transits to minimize any impact caused by the temporary deviation.

In accordance with 33 CFR 117.35(e), the drawbridge must return to its regular operating schedule immediately at the end of the designated time period. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: August 2, 2011.

Waverly W. Gregory, Jr.,

Bridge Program Manager, By direction of the Commander, Fifth Coast Guard District.

[FR Doc. 2011–20378 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2011–0703]

Drawbridge Operation Regulation; Beaufort Channel, Beaufort, NC

AGENCY: Coast Guard, DHS.

ACTION: Notice of temporary deviation from regulations.

SUMMARY: The Commander, Fifth Coast Guard District, has issued a temporary deviation from the regulation governing the operation of the Grayden Paul Bridge across the Beaufort (Gallants) Channel, mile 0.1 at Beaufort, NC. The deviation is necessary to accommodate racing participants for the ''Neuse Riverkeeper Foundation Sprint Triathlon''. This deviation allows the bridge to remain in the closed position during the race to ensure the safe and efficient passage of participants.

DATES: This deviation is effective from 11:30 a.m. to 1:30 p.m. on September 3, 2011.

ADDRESSES: Documents mentioned in this preamble as being available in the docket are part of docket USCG–2011–0703 and are available online by going to *http://www.regulations.gov,* inserting USCG–2011–0703 in the ''Keyword'' box and then clicking ''Search''. They are also available for inspection or copying at the Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or e-mail Lindsey Middleton, Coast Guard; telephone 757–398–6629, e-mail *Lindsey.R.Middleton@uscg.mil.* If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION: The Coastal Society, on behalf of the North Carolina Department of Transportation has requested a temporary deviation from the current operating regulations of the Grayden Paul Bridge, across the Beaufort (Gallants) Channel, mile 0.1, at Beaufort, NC. The bike route of the ''Neuse Riverkeeper Foundation Sprint Triathlon'' crosses the bridge and the requested deviation is to accommodate the participants. To facilitate this event, the draw of the bridge will be maintained in the closed-to-navigation position from 11:30 a.m. until 1:30 p.m. on Saturday, September 3, 2011.

The vertical clearance for this bridge in the closed position is 13 feet at Mean High Water and is limited to 77 feet in the open position due to the adjacent power lines. The operating regulations are set forth in 33 CFR 117.822 which states that the bridge shall open on the hour and on the half hour.

Vessels that can pass under the bridge in the closed position may do so at any time. The Coast Guard will inform the users of the waterway of the closure through our Local and Broadcast Notices to Mariners to minimize any impact caused by the temporary deviation. The bridge will be able to open for emergencies. This closure has been an annual closure for the past several years therefore there are no traffic logs with past openings for this time of year. Most of the vessel traffic consists of recreational and commercial fishing boats. Vessels can use the Intracoastal Waterway as an alternate route.

In accordance with 33 CFR 117.35(e), the drawbridge must return to its regular operating schedule immediately at the end of the designated time period. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: August 2, 2011.

Waverly W. Gregory, Jr.,

Bridge Program Manager, By Direction of the Commander, Fifth Coast Guard District.

[FR Doc. 2011–20373 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2010–0939]

RIN 1625–AA00

Safety Zone; M/V DAVY CROCKETT, Columbia River

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The U.S. Coast Guard is extending the enforcement of a safety zone established on the waters of the Columbia River surrounding the M/V DAVY CROCKETT at approximate river mile 117. The original safety zone was established on January 28, 2011. The safety zone is necessary to help ensure the safety of the response workers and maritime public from the hazards associated with ongoing salvage operations involving the M/V DAVY CROCKETT. All persons and vessels are prohibited from entering or remaining in the safety zone unless authorized by the Captain of the Port, Columbia River or his designated representative.

DATES: This rule is effective from August 11, 2011 through August 31, 2011. This rule is effective with actual notice for purposes of enforcement on August 1, 2011. This rule will remain in effect through August 31, 2011.

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket USCG–2010–0939 and are available online by going to *http://www.regulations.gov,* inserting USCG–2010–0939 in the ''Keyword'' box, and then clicking ''Search.'' They are also available for inspection or copying at the Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary rule, call or e-mail BM1 Silvestre Suga, Waterways Management Division, Marine Safety Unit Portland, Coast Guard; telephone 503–240–9319, e-mail *Silvestre.G.Suga@uscg.mil.* If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Regulatory Information

The Coast Guard is issuing this temporary final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because to do so would be contrary to public interest. The safety zone is immediately necessary to help ensure the safety of the response workers and the maritime public due to the ongoing salvage operations involving the M/V DAVY CROCKETT.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal**

Register because the safety zone is immediately necessary to help ensure the safety of the response workers and the maritime public due to the ongoing salvage operations involving the M/V DAVY CROCKETT.

Background and Purpose

The M/V DAVY CROCKETT, a 431 ft barge, is anchored on the Washington State side of the Columbia River at approximately river mile 117. The vessel is in a severe state of disrepair. The Coast Guard, other state and federal agencies, and federal contractors are working to remove the vessel. The salvage operations require a minimal wake in the vicinity of the vessel to help ensure the safety of response workers on or near the vessel and in the water. In addition, due the deleterious state of the vessel only authorized persons and/or vessels can be safely allowed on or near it.

A 300 ft safety zone is necessary to keep vessels clear of the ongoing salvage operations surrounding the M/V DAVY CROCKETT. The previous 300 ft safety zone will expire on July 31, 2011.

Discussion of Rule

The Coast Guard is extending the enforcement of the safety zone created by this rule until August 31, 2011. The safety zone will cover all waters of the Columbia River encompassed within the following four points: point one at 45°34′59.74″ N/122°28′35.00″ W on the Washington bank of the Columbia River then proceeding into the river to point two at 45°34′51.42″ N/122°28′35.47″ W, then proceeding upriver to the third point at 45°34′51.02″ N/122°28′07.32″ W, then proceeding to the shoreline to the fourth point on the Washington Bank at 45°34′56.06″ N/122°28′07.36″ W, then back along the shoreline to point one. Geographically this encompasses all the waters within an area starting at approximately 300 ft upriver from the M/V DAVY CROCKETT extending to 300 ft abreast of the M/V DAVY CROCKETT and then ending 300 ft down river of the M/V DAVY CROCKETT.

Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on 13 of these statutes or executive orders.

Regulatory Planning and Review

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order.

The Coast Guard has made this determination based on the fact that the safety zones created by this rule will not significantly affect the maritime public because the areas covered are limited in size and/or have little commercial or recreational activity. In addition, vessels may enter the safety zones with the permission of the Captain of the Port, Columbia River or his designated representative.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. This rule may affect the following entities some of which may be small entities: the owners and operators of vessels intending to operate in the areas covered by the safety zones created in this rule. The safety zones will not have a significant economic impact on a substantial number of small entities because the areas covered are limited in size. In addition, vessels may enter the safety zones with the permission of the Captain of the Port, Columbia River or his designated representative.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we offer to assist small entities in understanding the rule so that they can better evaluate its effects on them and participate in the rulemaking process.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

Collection of Information

This rule calls for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not cause a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminates ambiguity, and reduce burden.

Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

Energy Effects

We have analyzed this rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The Administrator of the Office of Information and Regulatory Affairs has not designated it as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

Technical Standards

The National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note) directs agencies to use voluntary consensus standards in their regulatory activities unless the agency provides Congress, through the Office of Management and Budget, with an explanation of why using these standards would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies.

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule is categorically excluded, under figure 2–1, paragraph (34)(g), of the Instruction. This rule involves the creation of safety zones. An environmental analysis checklist and a categorical exclusion determination will be available in the docket where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Public Law 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Revise § 165.T13–175 to read as follows:

§ 165.T13–175 Safety Zone; M/V DAVY CROCKETT, Columbia River

(a) *Location:* The following area is a safety zone:

(1) All waters of the Columbia River encompassed within the following four points: point one at 45°34′59.74″ N/122°28′35.00″ W on the Washington bank of the Columbia River then proceeding into the river to point two at 45°34′51.42″ N/122°28′35.47″ W, then proceeding upriver to the third point at 45°34′51.02″ N/122°28′07.32″ W, then proceeding to the shoreline to the fourth point on the Washington Bank at 45°34′56.06″ N/122°28′07.36″ W, then back along the shoreline to point one. Geographically this encompasses all the waters within an area starting at approximately 300 ft upriver from the M/V DAVY CROCKETT extending to 300 ft abreast of the M/V DAVY CROCKETT and then ending 300 ft down river of the M/V DAVY CROCKETT.

(b) *Regulations.* In accordance with the general regulations in 33 CFR part 165, subpart C, no person may enter or remain in the safety zone created in this section or bring, cause to be brought, or allow to remain in the safety zone created in this section any vehicle, vessel, or object unless authorized by the Captain of the Port, Columbia River or his designated representative.

(c) *Enforcement Period.* The safety zone created in this section will be in effect from August 1, 2011 through August 31, 2011 unless cancelled sooner by the Captain of the Port, Columbia River.

Dated: July 26, 2011.

B.C. Jones,

Captain, U.S. Coast Guard, Captain of the Port, Columbia River.

[FR Doc. 2011–20375 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2011–0672]

RIN 1625–AA00

Safety Zone; East Coast Drag Boat Bucksport Blowout Boat Race, Waccamaw River, Bucksport, SC

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone on the waters of the Waccamaw River during the East Coast Drag Boat Bucksport Blowout in Bucksport, South Carolina. The East Coast Drag Boat Bucksport Blowout will consist of a series of high-speed boat races. The event is scheduled to take place on Saturday, September 17, 2011 and Sunday, September 18, 2011. The temporary safety zone is necessary for the safety of race participants, participant vessels, spectators, and the general public during the event. Persons and vessels are prohibited from entering, transiting through, anchoring in, or remaining within the safety zone unless authorized by the Captain of the Port Charleston or a designated representative.

DATES: This rule is effective from 11:59 a.m. on September 17, 2011 through 7 p.m. on September 18, 2011.

ADDRESSES: Documents indicated in this preamble as being available in the docket are part of docket USCG–2011–0672 and are available online by going to *http://www.regulations.gov,* inserting USCG–2011–0672 in the ''Keyword'' box, and then clicking ''Search.'' They are also available for inspection or copying at the Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary final rule, call or e-mail Ensign John R. Santorum, Coast Guard Sector Charleston Waterways Management

Division at telephone: 843–740–3184, e-mail *John.R.Santorum@uscg.mil.* If you have questions on viewing the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Regulatory Information

The Coast Guard is issuing this temporary final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because the Coast Guard did not receive necessary information about the event until July 5, 2011. As a result, the Coast Guard did not have sufficient time to publish an NPRM and to receive public comments prior to the event. Any delay in the effective date of this rule would be contrary to the public interest because immediate action is needed to minimize potential danger to the race participants, participant vessels, spectators, and the general public.

Basis and Purpose

The legal basis for the rule is the Coast Guard's authority to establish regulated navigation areas and other limited access areas: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Public Law 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

The purpose of the rule is to protect race participants, participant vessels, spectators, and the general public from the hazards associated with the high-speed boat races.

Discussion of Rule

On September 17, 2011 and September 18, 2011, the East Coast Drag Boat Association will host the East Coast Drag Boat Bucksport Blowout, a series of high-speed boat races. The races will take place from approximately 11:59 a.m. until 7 p.m. on each day. The races will be held on the waters of the Waccamaw River in Bucksport, South Carolina. Approximately 30 high-speed power boats will be participating in the races. The high speed of the participant vessels poses a safety hazard to race participants, participant vessels, spectators, and the general public.

The safety zone encompasses certain waters of the Waccamaw River in Bucksport, South Carolina. The safety zone will be enforced daily from 11:59 a.m. until 7 p.m. Persons and vessels are prohibited from entering, transiting through, anchoring in, or remaining within the safety zone unless authorized by the Captain of the Port Charleston or a designated representative. Persons and vessels desiring to enter, transit through, anchor in, or remain within the safety zone may contact the Captain of the Port Charleston by telephone at 843–740–7050, or a designated representative via VHF radio on channel 16, to request authorization. If authorization to enter, transit through, anchor in, or remain within the safety zone is granted by the Captain of the Port Charleston or a designated representative, all persons and vessels receiving such authorization must comply with the instructions of the Captain of the Port Charleston or a designated representative. The Coast Guard will provide notice of the safety zone by Local Notice to Mariners, Broadcast Notice to Mariners, and on-scene designated representatives.

Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on 13 of these statutes or executive orders.

Executive Order 12866 and Executive Order 13563

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order.

The economic impact of this rule is not significant for the following reasons: (1) The safety zone will be enforced for a total of just over 14 hours; (2) although persons and vessels will not be able to enter, transit through, anchor in, or remain within the regulated area without authorization from the Captain of the Port Charleston or a designated representative, they may operate in the surrounding area during the enforcement period; (3) persons and vessels may still enter, transit through, anchor in, or remain within the safety zone if authorized by the Captain of the Port Charleston or a designated representative; and (4) the Coast Guard will provide advance notification of the safety zone to the local maritime community by Local Notice to Mariners and Broadcast Notice to Mariners.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule would have a significant economic impact on a substantial number of small entities. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. This rule may affect the following entities, some of which may be small entities: the owners or operators of vessels intending to enter, transit through, anchor in, or remain within that portion of the Waccamaw River encompassed within the safety zone from 11:59 a.m. until 7 p.m. on September 17, 2011 and September 18, 2011. For the reasons discussed in the Executive Order 12866 and Executive Order 13563 section above, this rule will not have a significant economic impact on a substantial number of small entities.

Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we offer to assist small entities in understanding the rule so that they can better evaluate its effects on them and participate in the rulemaking process.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

Collection of Information

This rule calls for no new collection of information under the Paperwork

Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

Taking of Private Property

This rule will not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

Energy Effects

We have analyzed this rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order because it is not a ''significant regulatory action'' under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The Administrator of the Office of Information and Regulatory Affairs has not designated it as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

Technical Standards

The National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note) directs agencies to use voluntary consensus standards in their regulatory activities unless the agency provides Congress, through the Office of Management and Budget, with an explanation of why using these standards would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies.

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded this action is one of a category of actions which do not individually or cumulatively have a significant effect on the human environment. This rule is categorically excluded, under figure 2–1, paragraph (34)(g), of the Instruction. This rule involves the establishment of a temporary safety zone that will be enforced for a total of just over 14 hours. An environmental analysis checklist and a categorical exclusion determination are available in the docket where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add a temporary § 165.T07–0672 to read as follows:

§ 165.T07–0672 Safety Zone; East Coast Drag Boat Bucksport Blowout Boat Race, Waccamaw River, Bucksport, SC.

(a) *Regulated Area.* The following regulated area is safety zone. All waters of the Waccamaw River encompassed within an imaginary line connecting the following points: starting at Point 1 in position 33°39′11.46″ N, 79°05′36.78″ W; thence west to Point 2 in position 33°39′12.18″ N, 79°05′47.76″ W; thence southeast to Point 3 in position 33°38′39.48″ N, 79°05′37.44″ W; thence northeast to Point 4 in position 33°38′42.3″ N, 79°05′30.6″ W; thence northwest back to origin. All coordinates are North American Datum 1983.

(b) *Definition.* The term ''designated representative'' means Coast Guard Patrol Commanders, including Coast Guard coxswains, petty officers, and other officers operating Coast Guard vessels, and Federal, state, and local officers designated by or assisting the Captain of the Port Charleston in the enforcement of the regulated area.

(c) *Regulations.* (1) All persons and vessels are prohibited from entering, transiting through, anchoring in, or remaining within the regulated area unless authorized by the Captain of the Port Charleston or a designated representative.

(2) Persons and vessels desiring to enter, transit through, anchor in, or remain within the regulated area may contact the Captain of the Port Charleston by telephone at 843–740–7050, or a designated representative via VHF radio on channel 16, to request authorization. If authorization to enter, transit through, anchor in, or remain within the regulated area is granted by the Captain of the Port Charleston or a designated representative, all persons

and vessels receiving such authorization must comply with the instructions of the Captain of the Port Charleston or a designated representative.

(3) The Coast Guard will provide notice of the regulated area by Local Notice to Mariners, Broadcast Notice to Mariners, and on-scene designated representatives.

(d) *Effective Date and Enforcement Periods.* This rule is effective from 11:59 a.m. on September 17, 2011 through 7 p.m. on September 18, 2011. This rule will be enforced daily from 11:59 a.m. until 7 p.m. on September 17, 2011 and September 18, 2011.

Dated: August 1, 2011.

M.F. White,

Captain, U.S. Coast Guard, Captain of the Port Charleston.

[FR Doc. 2011–20377 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 21

RIN 2900–AO10

Vocational Rehabilitation and Employment Program—Changes to Subsistence Allowance

Correction

In rule document 2011–19473 appearing on pages 45697–45705 in the issue of August 1, 2011, make the following correction:

In the table on page 45703, in the first row, under the column ''Year dollar'', ''2010'' should read ''2012''.

[FR Doc. C1–2011–19473 Filed 8–10–11; 8:45 am]

BILLING CODE 1505–01–D

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 1, 2, 21, 35, 49, 52, 59, 60, 61, 62, 63, 65, 82, 147, 282, 374, 707, and 763

[FRL–9449–3]

Change of Address for Region 1; Technical Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; technical amendment.

SUMMARY: The Environmental Protection Agency (EPA) is amending its regulations to reflect a change in address for EPA's Region 1 office. This action is editorial in nature and is intended to provide accuracy and clarity to the agency's regulations.

DATES: This final rule is effective August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Donald O. Cooke, Air Quality Planning Unit, U.S. Environmental Protection Agency, EPA Region 1, Office of Ecosystem Protection, Air Quality Planning Unit, 5 Post Office Square—Suite 100, (Mail code OEP05–2), Boston, MA 02109–3912, telephone number (617) 918–1668, fax number (617) 918–0668, e-mail *cooke.donald@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

EPA is amending its regulations in 40 CFR parts 1, 2, 21, 35, 49, 52, 59, 60, 61, 62, 63, 65, 82, 147, 282, 374, 707, and 763 to reflect a change in the address for EPA's Region 1 office. This technical amendment merely updates and corrects the address for EPA's Region 1 office. Consequently, EPA has determined that today's rule falls under the ''good cause'' exemption in section 553(b)(3)(B) of the Administrative Procedures Act (APA) which, upon finding ''good cause,'' authorizes agencies to dispense with public participation and section 553(d)(3) which allows an agency to make a rule effective immediately (thereby avoiding the 30-day delayed effective date otherwise provided for in the APA). Under section 553 of the APA, an agency may find good cause where procedures are ''impractical, unnecessary, or contrary to the public interest.'' Public comment is ''unnecessary'' and ''contrary to the public interest'' since the address for Region 1 has changed and immediate notice in the CFR benefits the public by updating citations.

II. Statutory and Executive Order Reviews

This final rule implements technical amendments to 40 CFR parts 1, 2, 21, 35, 49, 52, 59, 60, 61, 62, 63, 65, 82, 147, 282, 374, 707, and 763 to reflect a change in the address for EPA's Region 1 office. It does not otherwise impose or amend any requirements. Consequently, under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a ''significant regulatory action'' and therefore is not subject to review by the Office of Management and Budget. The rule would not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). Because this action is merely editorial in nature, the Administrator certifies that it would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). The rule does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

This action does not have Federalism implications because it would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). Additionally, it does not have Tribal implications because it would not have a substantial direct effect on one or more Indian Tribes, on the relationship between the Federal Government and Indian Tribes, or on the distribution of power and responsibilities between the Federal Government and Indian Tribes, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

This rule also is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), nor is it subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001). It does not involve any technical standards that require the Agency's consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995, Public Law 104–113, section 12(d) (15 U.S.C. 272 note). Finally, it does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods under Executive Order 12898 (59 FR 7629, February 16, 1994).

III. Congressional Review Act

The Congressional Review Act (CRA), 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. Section 808 of the CRA allows the issuing agency to make a rule effective sooner than otherwise provided by the CRA, if the agency makes a good cause finding that notice and public procedure is impracticable, unnecessary, or contrary to the public interest. This determination must be supported by a brief statement (5 U.S.C. 808(2)). As stated earlier, EPA has made such a good cause finding, including the reasons therefore, and established an effective date of August 11, 2011. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 1

Environmental protection, Organization and functions (Government agencies).

40 CFR Part 2

Environmental protection, Administrative practice and procedure, Confidential business information, Courts, Freedom of information, Government employees.

40 CFR Part 21

Environmental protection, Administrative practice and procedure, Small businesses, Water pollution control.

40 CFR Part 35

Environmental protection, Air pollution control, Coastal zone, Grant programs—environmental protection, Grant programs—Indians, Hazardous waste, Indians, Intergovernmental relations, Pesticides and pests, Reporting and recordkeeping requirements, Technical assistance, Waste treatment and disposal, Water pollution control, Water supply.

40 CFR Part 49

Environmental protection, Administrative practice and procedure, Air pollution control, Indians, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Incorporation by reference, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

40 CFR Part 59

Environmental protection, Air pollution control, Confidential business information, Labeling, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Aluminum, Ammonium sulfate plants, Batteries, Beverages, Carbon monoxide, Cement industry, Chemicals, Coal, Copper, Dry cleaners, Electric power plants, Fertilizers, Fluoride, Gasoline, Glass and glass products, Grains, Graphic arts industry, Heaters, Household appliances, Insulation, Intergovernmental relations, Iron, Labeling, Lead, Lime, Metallic and nonmetallic mineral processing plants, Metals, Motor vehicles, Natural gas, Nitric acid plants, Nitrogen dioxide, Paper and paper products industry, Particulate matter, Paving and roofing materials, Petroleum, Phosphate, Plastics materials and synthetics, Polymers, Reporting and recordkeeping requirements, Sewage disposal, Steel, Sulfur oxides, Sulfuric acid plants, Tires, Urethane, Vinyl, Volatile organic compounds, Waste treatment and disposal, Zinc.

40 CFR Part 61

Environmental protection, Air pollution control, Arsenic, Asbestos, Benzene, Beryllium, Hazardous substances, Mercury, Radionuclides, Radon, Reporting and recordkeeping requirements, Uranium, Vinyl chloride.

40 CFR Part 62

Environmental protection, Administrative practice and procedure, Air pollution control, Aluminum, Fertilizers, Fluoride, Intergovernmental relations, Paper and paper products industry, Phosphate, Reporting and recordkeeping requirements, Sulfur oxides, Sulfuric acid plants, Waste treatment and disposal.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 65

Environmental protection, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 82

Environmental protection, Administrative practice and procedure, Air pollution control, Chemicals, Exports, Government procurement, Imports, Labeling, Reporting and recordkeeping requirements.

40 CFR Part 147

Environmental protection, Indians—lands, Intergovernmental relations, Reporting and recordkeeping requirements, Water supply.

40 CFR Part 282

Environmental protection, Hazardous substances, Insurance, Intergovernmental relations, Oil pollution, Surety bonds, Water pollution control, Water supply.

40 CFR Part 374

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Hazardous waste, Natural resources, Superfund, Water pollution control, Water supply.

40 CFR Part 707

Environmental protection, Chemicals, Environmental protection, Exports, Hazardous substances, Reporting and recordkeeping requirements.

40 CFR Part 763

Environmental protection, Administrative practice and procedure, Asbestos, Confidential business information, Environmental protection, Hazardous substances, Imports, Intergovernmental relations, Labeling, Occupational safety and health, Reporting and recordkeeping requirements, Schools.

Dated: July 20, 2011.

Ira W. Leighton,

Acting Regional Administrator, EPA Region I.

40 CFR parts 1, 2, 21, 35, 49, 52, 59, 60, 61, 62, 63, 65, 82, 147, 282, 374, 707, and 763 are amended as follows:

PART 1—[AMENDED]

■ 1. The authority citation for part 1 continues to read as follows:

Authority: 5 U.S.C. 552.

Subpart A—Introduction

■ 2. Section 1.7 is amended by revising paragraph (b)(1) to read as follows:

§ 1.7 Location of principal offices.

* * * * *

(1) Region I, U.S. Environmental Protection Agency, 5 Post Office Square—Suite 100, Boston, MA 02109–

3912. (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.)

* * * * *

PART 2—[AMENDED]

■ 3. The authority citation for part 2 continues to read as follows:

Authority: 5 U.S.C. 301, 552 (as amended), 553; secs. 114, 205, 208, 301, and 307, Clean Air Act, as amended (42 U.S.C. 7414, 7525, 7542, 7601, 7607); secs. 308, 501 and 509(a), Clean Water Act, as amended (33 U.S.C. 1318, 1361, 1369(a)); sec. 13, Noise Control Act of 1972 (42 U.S.C. 4912); secs. 1445 and 1450, Safe Drinking Water Act (42 U.S.C. 300j–4, 300j–9); secs. 2002, 3007, and 9005, Solid Waste Disposal Act, as amended (42 U.S.C. 6912, 6927, 6995); secs. 8(c), 11, and 14, Toxic Substances Control Act (15 U.S.C. 2607(c), 2610, 2613); secs. 10, 12, and 25, Federal Insecticide, Fungicide, and Rodenticide Act, as amended (7 U.S.C. 136h, 136j, 136w); sec. 408(f), Federal Food, Drug and Cosmetic Act, as amended (21 U.S.C. 346(f)); secs. 104(f) and 108, Marine Protection Research and Sanctuaries Act of 1972 (33 U.S.C. 1414(f), 1418); secs. 104 and 115, Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (42 U.S.C. 9604 and 9615); sec. 505, Motor Vehicle Information and Cost Savings Act, as amended (15 U.S.C. 2005).

Subpart A—Procedures for Disclosure of Records Under the Freedom of Information Act

■ 4. Section 2.101 is amended by revising paragraph (a)(1) to read as follows:

§ 2.101 Where requests for records are to be filed.

* * * * *

(a) * * *

(1) Region I (CT, ME, MA, NH, RI, VT): US EPA, FOI Officer, 5 Post Office Square—Suite 100, Boston, MA 02109–3912; e-mail: *r1foia@epa.gov.*

* * * * *

PART 21—[AMENDED]

■ 5. The authority citation for part 21 continues to read as follows:

Authority: (15 U.S.C. 636), as amended by Pub. L. 92–500.

■ 6. Section 21.3 is amended by revising the first entry for Region I in the table in paragraph (a) to read as follows:

§ 21.3 Submission of applications.

(a) * * *

Region	Address	State
I	Regional Administrator, Region I, EPA, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
* * *	* *	* *

PART 35—[AMENDED]

■ 7. The authority citation for part 35 continues to read as follows:

Authority: 42 U.S.C. 4368b, unless otherwise noted.

Subpart M—Grants for Technical Assistance

■ 8. Section 35.4275 is amended by revising paragraph (a) to read as follows:

§ 35.4275 Where can my group get the documents this subpart references (for example, OMB circulars, other subparts, forms)?

(a) TAG Coordinator or Grants Office, U.S. EPA Region I, 5 Post Office Square—Suite 100, Boston, MA 02109–3912

* * * * *

PART 49—[AMENDED]

■ 9. The authority citation for part 49 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart D—Implementation Plans for Tribes—Region I

■ 10. Section 49.201 is amended by revising paragraph (b)(3) to read as follows:

§ 49.201 Identification of plan.

* * * * *

(b) * * *

(3) Copies of the materials incorporated by reference may be inspected at the New England Regional Office of EPA at 5 Post Office Square—Suite 100, Boston, MA 02109–3912; the U.S. Environmental Protection Agency, EPA Docket Center (EPA/DC), Air and Radiation Docket and Information Center, MC 2822T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460 and the National Archives and Records Administration. If you wish to obtain material from the EPA Regional Office, please call 617–918–1653; for materials from the docket in EPA Headquarters Library, please call the Office of Air and Radiation docket at 202–566–1742. For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

* * * * *

PART 52—[AMENDED]

■ 11. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 12. Section 52.02 is amended by revising paragraph (d)(2)(i) to read as follows:

§ 52.02 Introduction.

* * * * *

(d) * * *

(2) * * *

(i) Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Environmental Protection Agency, Region 1, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

■ 13. Section 52.16 is amended by revising paragraph (b)(1) to read as follows:

§ 52.16 Submission to Administrator.

* * * * *

(b) * * *

(1) Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. EPA Region 1, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

Subpart U—Maine

■ 14. Section 52.1020 is amended by revising paragraph (b)(3) to read as follows:

§ 52.1020 Identification of plan.

* * * * *

(b) * * *

(3) Copies of the materials incorporated by reference may be inspected at the Environmental Protection Agency, New England Regional Office, 5 Post Office Square—Suite 100, Boston, MA 02109–3912; Air and Radiation Docket and Information

Center, EPA West Building, 1301 Constitution Ave., NW., Washington, DC 20460; and the National Archives and Records Administration (NARA). If you wish to obtain materials from a docket in the EPA Headquarters Library, please call the Office of Air and Radiation (OAR) Docket/Telephone number (202) 566–1742. For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

* * * * *

Subpart EE—New Hampshire

■ 15. Section 52.1520 is amended by revising paragraph (b)(3) to read as follows:

§ 52.1520 Identification of plan.

* * * * *

(b) * * *

(3) Copies of the materials incorporated by reference may be inspected at the Environmental Protection Agency, New England Regional Office, 5 Post Office Square—Suite 100, Boston, MA 02109–3912; Air and Radiation Docket and Information Center, EPA West Building, 1301 Constitution Ave., NW., Washington, DC 20460; and the National Archives and Records Administration (NARA). If you wish to obtain materials from the EPA Regional Office, please call (617) 918–1668; for materials from a docket in the EPA Headquarters Library, please call the Office of Air and Radiation (OAR) Docket at (202) 566–1742. For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

* * * * *

Subpart OO—Rhode Island

■ 16. Section 52.2070 is amended by revising in paragraph (b)(3) to read as follows:

§ 52.2070 Identification of plan.

* * * * *

(b) * * *

(3) Copies of the materials incorporated by reference may be inspected at the New England Regional Office of EPA at 5 Post Office Square—Suite 100, Boston, MA 02109–3912; the EPA, Air and Radiation Docket and Information Center, Room Number 3334, EPA West Building, 1301 Constitution Ave., NW., Washington, DC 20460, and the National Archives and Records Administration [NARA]. If you wish to obtain materials from a docket in the EPA Regional Office, please call telephone number (617) 918–1668; for material from a docket in EPA Headquarters Library, please call the Office of Air and Radiation (OAR) Docket/Telephone number (202) 566–1742. For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

* * * * *

Subpart UU—Vermont

■ 17. Section 52.2370 is amended by revising paragraph (b)(3) to read as follows:

§ 52.2370 Identification of plan.

* * * * *

(b) * * *

(3) Copies of the materials incorporated by reference may be inspected at the New England Regional Office of EPA at 5 Post Office Square—Suite 100, Boston, MA 02109–3912; the EPA, Air and Radiation Docket and Information Center, Air Docket (Mail Code 6102T), Room B–108, 1301 Constitution Avenue, NW., Washington, DC 20460 and the National Archives and Records Administration. For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

* * * * *

PART 59—[AMENDED]

■ 18. The authority citation for part 59 continues to read as follows:

Authority: 42 U.S.C. 7414 and 7511b(e).

Subpart B—National Volatile Organic Compound Emission Standards for Automobile Refinish Coatings

■ 19. Section 59.107 is amended by revising the address for Region I to read as follows:

§ 59.107 Addresses of EPA Regional Offices.

* * * * *

EPA Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Environmental Stewardship, Mailcode: OES04–5, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

Subpart C—National Volatile Organic Compound Emission Standards for Consumer Products

■ 20. Section 59.210 is amended by revising the address for Region I to read as follows:

§ 59.210 Addresses of EPA Regional Offices.

* * * * *

EPA Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Ecosystem Protection, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

Subpart D—National Volatile Organic Compound Emission Standards for Architectural Coatings

■ 21. Section 59.409 is amended by revising the address for Region I in paragraph (a) to read as follows:

§ 59.409 Addresses of EPA Offices.

(a) * * *

EPA Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Environmental Stewardship, Mailcode: OES04–5, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

Subpart E—National Volatile Organic Compound Emission standards for Aerosol Coatings

■ 22. Section 59.512 is amended by revising the address for Region I to read as follows:

§ 59.512 Addresses of EPA regional offices.

* * * * *

EPA Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Environmental Stewardship, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 60—[AMENDED]

■ 23. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 24. Section 60.4 is amended by revising the address for Region I in paragraph (a) to read as follows:

§ 60.4 Address.

(a) * * * Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Ecosystem Protection, U.S. Environmental Protection Agency, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 61—[AMENDED]

■ 25. The authority citation for part 61 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 26. Section 61.04 is amended by revising the address for Region I in paragraph (a) to read as follows:

§ 61.04 Address.

(a) * * *

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Ecosystem Protection, U.S. Environmental Protection Agency, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 62—[AMENDED]

■ 27. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 28. Section 62.10 is amended by revising the first entry for Region I address in the table to read as follows:

§ 62.10 Submission to Administrator.

* * * * *

Region and jurisdiction covered	Address
I—Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.	5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * * * *

PART 63—[AMENDED]

■ 29. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 30. Section 63.13 is amended by revising the address for Region I in paragraph (a) to read as follows:

§ 63.13 Addresses of State air pollution control agencies and EPA Regional Offices.

(a) * * *

EPA Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Ecosystem Protection, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 65—[AMENDED]

■ 31. The authority citation for part 65 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 32. Section 65.14 is amended by revising the address for Region I in paragraph (a) to read as follows:

§ 65.14 Addresses.

(a) * * *

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Office of Ecosystem Protection, U.S. Environmental Protection Agency, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 82—[AMENDED]

■ 33. The authority citation for part 82 continues to read as follows:

Authority: 42 U.S.C. 7414, 7601, 7671–7671q.

Subpart B—Servicing of Motor Vehicle Air Conditioners

■ 34. Section 82.42 is amended by revising paragraph (a)(1)(iii)(A) to read as follows:

§ 82.42 Certification, recordkeeping and public notification requirements.

(a) * * *

(1) * * *

(iii) * * *

(A) Owners or lessees of recycling or recovery equipment having their places of business in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont must send their certifications to: CAA section 609 Enforcement Contact; EPA Region I; Mail Code OES04–5; 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

Subpart F—Recycling and Emissions Reduction

■ 35. Section 82.162 is amended by revising the address for Region I in paragraph (a)(5) to read as follows:

§ 82.162 Certification by owners of recovery and recycling equipment.

(a) * * *

(5) The certification must also include a statement that the equipment will be properly used in servicing or disposing of appliances and that the information given is true and correct. Owners or lessees of recycling or recovery equipment having their places of business in: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont must send their certifications to: CAA section 608 Enforcement Contact; EPA Region I; Mail Code OES04–5; 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 147—[AMENDED]

■ 36. The authority citation for part 147 continues to read as follows:

Authority: 42 U.S.C. 300h *et seq.;* and 42 U.S.C. 6901 *et seq.*

Subpart H—Connecticut

■ 37. Section 147.350 is amended by revising paragraph (a) introductory text to read as follows:

§ 147.350 State-administered program.

* * * * *

(a) Incorporation by reference. The requirements set forth in the State statutes and regulations cited in this paragraph are hereby incorporated by reference and made part of the applicable UIC program under the SDWA for the State of Connecticut. This incorporation by reference was approved by the Director of the OFR in accordance with 5 U.S.C. 552(a) and CFR part 51. Copies may be obtained at the State of Connecticut, Department of Environmental Protection, State Office Building, 165 Capitol Avenue, Hartford, Connecticut, 06106. Copies may be inspected at the Environmental Protection Agency, Region I, 5 Post Office Square—Suite 100, Boston, MA

02109–3912, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

* * * * *

PART 282—[AMENDED]

■ 38. The authority citation for part 282 continues to read as follows:

Authority: 42 U.S.C. 6912, 6991c, 6991d, and 6991e.

Subpart A—General Provisions

■ 39. Section 282.2 is amended by revising paragraph (b)(1) to read as follows:

§ 282.2 Incorporation by reference.

* * * * *

(b) * * *

(1) Region 1 (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont): 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 374—[AMENDED]

■ 40. The authority citation for part 374 continues to read as follows:

Authority: 42 U.S.C. 9659.

■ 41. Section 374.6 is amended by revising the address for Region I to read as follows:

§ 374.6 Addresses.

* * * * *

Regional Administrator, Region I, U.S. Environmental Protection Agency, 5 Post Office Square—Suite 100, Boston, MA 02109–3912.

* * * * *

PART 707—[AMENDED]

■ 42. The authority citation for part 707 continues to read as follows:

Authority: 15 U.S.C. 2611(b) and 2612.

Subpart B—General Import Requirements and Restrictions

■ 43. Section 707.20 is amended by revising the address for Region I in paragraph (c)(2)(ii) to read as follows:

§ 707.20 Chemical substances import policy.

* * * * *

(c) * * *

(2) * * *

(ii) * * *

Region I

5 Post Office Square—Suite 100, Boston, MA 02109–3912 (617–918–1700).

* * * * *

PART 763—[AMENDED]

■ 44. The authority citation for part 763 continues to read as follows:

Authority: 15 U.S.C. 2605, 2607(c), 2643, and 2646.

Subpart E—Asbestos Containing Materials in Schools

■ 45. Appendix C is amended by revising the address for Region I under II.C.3. to read as follows:

Appendix C to Subpart E of Part 763—Asbestos Model Accreditation Plan

* * * * *

II. * * *

C. * * *

3. * * *

EPA, Region I, (OES05–1) Asbestos Coordinator, 5 Post Office Square—Suite 100, Boston, MA 02109–3912, (617) 918–1016.

* * * * *

■ 46. Appendix D is amended by revising the address for Region I to read as follows:

Appendix D to Subpart E of Part 763—Transport and Disposal of Asbestos Waste

* * * * *

Region I

Asbestos NESHAPs Contact, Office of Environmental Stewardship, USEPA, Region I, 5 Post Office Square—Suite 100, Boston, MA 02109–3912, (617) 918–1551.

* * * * *

[FR Doc. 2011–20035 Filed 8–10–11; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 65

[Docket ID FEMA–2011–0002; Internal Agency Docket No. FEMA–B–1209]

Changes in Flood Elevation Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Interim rule.

SUMMARY: This interim rule lists communities where modification of the Base (1% annual-chance) Flood Elevations (BFEs) is appropriate because of new scientific or technical data. New flood insurance premium rates will be calculated from the modified BFEs for new buildings and their contents.

DATES: These modified BFEs are currently in effect on the dates listed in the table below and revise the Flood Insurance Rate Maps (FIRMs) in effect prior to this determination for the listed communities.

From the date of the second publication of these changes in a newspaper of local circulation, any person has ninety (90) days in which to request through the community that the Deputy Federal Insurance and Mitigation Administrator reconsider the changes. The modified BFEs may be changed during the 90-day period.

ADDRESSES: The modified BFEs for each community are available for inspection at the office of the Chief Executive Officer of each community. The respective addresses are listed in the table below.

FOR FURTHER INFORMATION CONTACT: Luis Rodriguez, Chief, Engineering Management Branch, Federal Insurance and Mitigation Administration, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–4064, or (e-mail) *luis.rodriguez1@dhs.gov.*

SUPPLEMENTARY INFORMATION: The modified BFEs are not listed for each community in this interim rule. However, the address of the Chief Executive Officer of the community where the modified BFE determinations are available for inspection is provided.

Any request for reconsideration must be based on knowledge of changed conditions or new scientific or technical data.

The modifications are made pursuant to section 201 of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4105, and are in accordance with the National Flood Insurance Act of 1968, 42 U.S.C. 4001 *et seq.,* and with 44 CFR part 65.

For rating purposes, the currently effective community number is shown and must be used for all new policies and renewals.

The modified BFEs are the basis for the floodplain management measures that the community is required either to adopt or to show evidence of being already in effect in order to qualify or to remain qualified for participation in the National Flood Insurance Program (NFIP).

These modified BFEs, together with the floodplain management criteria required by 44 CFR 60.3, are the minimum that are required. They should not be construed to mean that the community must change any existing ordinances that are more stringent in their floodplain management requirements. The community may at any time enact stricter requirements of its own or pursuant to policies established by other Federal, State, or regional entities. The changes in BFEs are in accordance with 44 CFR 65.4.

National Environmental Policy Act. This interim rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Consideration. An environmental impact assessment has not been prepared.

Regulatory Flexibility Act. As flood elevation determinations are not within the scope of the Regulatory Flexibility Act, 5 U.S.C. 601–612, a regulatory flexibility analysis is not required.

Regulatory Classification. This interim rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866 of September 30, 1993, Regulatory Planning and Review, 58 FR 51735.

Executive Order 13132, Federalism. This interim rule involves no policies that have federalism implications under Executive Order 13132, Federalism.

Executive Order 12988, Civil Justice Reform. This interim rule meets the applicable standards of Executive Order 12988.

List of Subjects in 44 CFR Part 65

Flood insurance, Floodplains, Reporting and recordkeeping requirements.

Accordingly, 44 CFR part 65 is amended to read as follows:

PART 65—[AMENDED]

■ 1. The authority citation for part 65 continues to read as follows:

Authority: 42 U.S.C. 4001 *et seq.;* Reorganization Plan No. 3 of 1978, 3 CFR, 1978 Comp., p. 329; E.O. 12127, 44 FR 19367, 3 CFR, 1979 Comp., p. 376.

§ 65.4 [Amended]

The tables published under the authority of § 65.4 are amended as follows:

State and county	Location and case No.	Date and name of newspaper where notice was published	Chief executive officer of community	Effective date of modification	Community No.
Connecticut: Hartford	City of Hartford (10–01–1797P).	February 16, 2011; February 23, 2011; *The Hartford Courant*.	The Honorable Pedro E. Segarra, Mayor, City of Hartford, 550 Main Street, 2nd Floor, Room 200, Hartford, CT 06103.	June 23, 2011	095080
Illinois:					
Adams	City of Quincy, (11–05–0757P).	February 7, 2011; February 14, 2011; *The Quincy Herald-Whig*.	The Honorable John A. Spring, Mayor, City of Quincy, City Hall, 730 Maine Street, Quincy, IL 62301.	June 15, 2011	170003
Adams	Unincorporated areas of Adams County, (11–05–0757P).	February 7, 2011; February 14, 2011; *The Quincy Herald-Whig*.	The Honorable Mike Mclaughlin, Chairman, Adams County Board, Adams County Courthouse, 507 Vermont Street, Quincy, IL 62301.	June 15, 2011	170001
Kansas: Rice	City of Sterling, (11–07–0838P).	April 14, 2011; April 21, 2011; *The Sterling Kansas Bulletin*.	The Honorable Todd Rowland, Mayor, City of Sterling, 114 North Broadway, P.O. Box 287, Sterling, KS 67579.	August 19, 2011	200297
Massachusetts: Essex.	City of Salem, (10–01–0551P).	February 10, 2011; February 17, 2011; *The Salem Evening News*.	The Honorable Kimberley Driscoll, Mayor, City of Salem, City Hall, 93 Washington Street, Salem, MA 01970.	January 26, 2011	250102
Missouri:					
Greene	City of Springfield, (10–07–2268P).	April 7, 2011; April 14, 2011; *The Springfield News-Leader*.	The Honorable James O'Neal, Mayor, City of Springfield, P.O. Box 8368, 840 Boonville Avenue, Springfield, MO 65801.	August 12, 2011	290149
Cass	City of Harrisonville, (10–07–2115P).	April 15, 2011; April 22, 2011; *The Cass County Democrat, Missourian*.	The Honorable Kevin Wood, Mayor, City of Harrisonville, 300 East Pearl Street, P.O. Box 367, Harrisonville, MO 64701.	August 22, 2011	290068
Nebraska: Lancaster	City of Lincoln, (11–07–1426P).	April 14, 2011; April 21, 2011; *The Lincoln Journal Star*.	The Honorable Chris Beutler, Mayor, City of Lincoln, 555 South 10th Street, Suite 301, Lincoln, NE 68508.	March 30, 2011	315273
North Carolina:					
Union	Unincorporated areas of Union County, (11–04–1541P).	June 2, 2011; June 9, 2011; *The Charlotte Observer* and, *The Enquirer-Journal*.	Ms. Cynthia Coto, Union County Manager, Union County Government Center, 500 North Main Street, Room 918, Monroe, NC 28112.	October 7, 2011	370234
Union	Village of Marvin, (11–04–1541P).	June 2, 2011; June 9, 2011; *The Charlotte Observer* and, *The Enquirer-Journal*.	The Honorable Nick Dispenziere, Mayor, Village of Marvin, 10004 New Town Road, Marvin, NC 28173.	October 7, 2011	370514
Ohio:					
Franklin	Unincorporated areas of Franklin County, (11–05–3271P).	May 16, 2011; May 23, 2011; *The Daily Reporter*.	Ms. Marilyn Brown, President, Franklin County, 373 South High Street, 26th Floor, Columbus, OH 43215.	May 2, 2011	390167
Franklin	City of Columbus, (11–05–3271P).	May 16, 2011; May 23, 2011; *The Daily Reporter*.	The Honorable Michael B. Coleman, Mayor, City of Columbus, 90 West Board Street, City Hall, 2nd Floor, Columbus, OH 43215.	May 2, 2011	390170
Montgomery	City of Kettering, (10–05–4843P).	February 10, 2011; February 17, 2011; *The Dayton Daily News*.	The Honorable Don Patterson, Mayor, City of Kettering, 3600 Shroyer Road, Kettering, OH 45429.	June 17, 2011	390412
Butler	City of Monroe, (11–05–2538P).	March 10, 2011; March 17, 2011; *The Middletown Journal*.	The Honorable Robert E. Routson, Mayor, City of Monroe, 233 South Main Street, P.O. Box 330, Monroe, OH 45050.	March 1, 2011	390042
Warren	Unincorporated areas of Warren County, (11–05–2538P).	March 10, 2011; March 17, 2011; *The Middletown Journal*.	Mr. David G. Young, Warren County Commissioner, 406 Justice Drive, 1st Floor, Lebanon, OH 45036.	March 1, 2011	390757

State and county	Location and case No.	Date and name of newspaper where notice was published	Chief executive officer of community	Effective date of modification	Community No.
Washington:					
Pierce	City of Sumner, (10–10–0620P).	April 11, 2011; April 18, 2011; *The News Tribune*.	The Honorable Dave Enslow, Mayor, City of Sumner, City Hall, 1104 Maple Street, Sumner, WA 98390.	August 16, 2011	530147
King	Unincorporated areas of King County, (10–10–0977P).	May 5, 2011; May 12, 2011; *The Seattle Times*.	Mr. Dow Constantine, King County Executive, 401 5th Avenue, Suite 800, Seattle, WA 98104.	April 25, 2011	530071
King	City of Burien, (10–10–0977P).	May 5, 2011; May 12, 2011; *The Seattle Times*.	The Honorable Joan McGilton, Mayor, City of Burien, 400 Southwest 152nd Street, Suite 300, Burien, WA 98166.	April 25, 2011	530321
Wisconsin:					
Dane	Unincorporated areas of Dane County, (10–05–5471P).	March 3, 2011; March 10, 2011; *The News-Sickle-Arrow*.	Ms. Kathleen Falk, Dane County Executive, County Building, Room 421, 210 Martin Luther King Jr. Boulevard, Madison, WI 53703.	July 8, 2011	550077
Dane	Village of Cross Plains, (10–05–5471P).	March 3, 2011; March 10, 2011; *The News-Sickle-Arrow*.	Mr. Mike Schutz, President, Village of Cross Plains, 2417 Brewery Road, Cross Plains, WI 53528.	July 8, 2011	550081
Brown	Village of Pulaski, (10–05–6098P).	February 24, 2011; March 3, 2011; *The Greenbay Press Gazette*.	Mr. Keith Chambers, President, Village of Pulaski, 421 South Saint Augustine Street, Pulaski, WI 54162.	July 5, 2011	550024
Brown	Unincorporated areas of Brown County, (10–05–6098P).	February 24, 2011; March 3, 2011; *The Greenbay Press Gazette*.	The Honorable Guy Zima, Chairman, Brown County Board, 305 East Walnut Street, Green Bay, WI 54301.	July 5, 2011	550020
Fond du Lac	Unincorporated areas of Fond du Lac County, (10–05–4703P).	May 16, 2011; May 23, 2011; *The Reporter*.	Mr. Allen J. Buechel, Fond du Lac County Executive, 160 South Macy Street, Fond du Lac, WI 54935.	September 20, 2011	550131
Fond du Lac	Village of Rosendale, (10–05–4703P).	May 16, 2011; May 23, 2011; *The Reporter*.	Mr. James Westphal, President, Village of Rosendale, 221 North Grant Street, Rosendale, WI 54974.	September 20, 2011	550141
Sauk	Village of Lake Delton, (10–05–6994P).	March 30, 2011; April 6, 2011; *The Wisconsin Dells Event*.	Mr. John Webb, President, Village of Lake Delton, 50 Wisconsin Dells Parkway South, P.O. Box 87, Lake Delton, WI 53940.	August 4, 2011	550394
Milwaukee	City of Greenfield, (11–05–1089P).	April 14, 2011; April 21, 2011; *The Greenfield Now*.	The Honorable Michael J. Neitzke, Mayor, City of Greenfield, 7325 West Forest Home Avenue, Greenfield, WI 53220.	March 31, 2011	550277

(Catalog of Federal Domestic Assistance No. 97.022, ''Flood Insurance.'')

Dated: July 29, 2011.

Sandra K. Knight,

Deputy Federal Insurance and Mitigation Administrator, Mitigation, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. 2011–20396 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–12–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 67

[Docket ID FEMA–2011–0002]

Final Flood Elevation Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Final rule.

SUMMARY: Base (1% annual-chance) Flood Elevations (BFEs) and modified BFEs are made final for the communities listed below. The BFEs and modified BFEs are the basis for the floodplain management measures that each community is required either to adopt or to show evidence of being already in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP).

DATES: The date of issuance of the Flood Insurance Rate Map (FIRM) showing BFEs and modified BFEs for each community. This date may be obtained by contacting the office where the maps are available for inspection as indicated in the table below.

ADDRESSES: The final BFEs for each community are available for inspection at the office of the Chief Executive Officer of each community. The respective addresses are listed in the table below.

FOR FURTHER INFORMATION CONTACT: Luis Rodriguez, Chief, Engineering Management Branch, Federal Insurance and Mitigation Administration, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–4064, or (e-mail) *luis.rodriguez1@dhs.gov.*

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) makes the final determinations listed below for the modified BFEs for each community listed. These modified elevations have been published in newspapers of local circulation and ninety (90) days have elapsed since that publication. The Deputy Federal Insurance and Mitigation Administrator has resolved any appeals resulting from this notification.

This final rule is issued in accordance with section 110 of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4104, and 44 CFR part 67. FEMA has developed criteria for floodplain management in floodprone areas in accordance with 44 CFR part 60.

Interested lessees and owners of real property are encouraged to review the proof Flood Insurance Study and FIRM available at the address cited below for each community. The BFEs and modified BFEs are made final in the communities listed below. Elevations at selected locations in each community are shown.

National Environmental Policy Act. This final rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Consideration. An environmental impact assessment has not been prepared.

Regulatory Flexibility Act. As flood elevation determinations are not within the scope of the Regulatory Flexibility Act, 5 U.S.C. 601–612, a regulatory flexibility analysis is not required.

Regulatory Classification. This final rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866 of September 30, 1993, Regulatory Planning and Review, 58 FR 51735.

Executive Order 13132, Federalism. This final rule involves no policies that have federalism implications under Executive Order 13132.

Executive Order 12988, Civil Justice Reform. This final rule meets the applicable standards of Executive Order 12988.

List of Subjects in 44 CFR Part 67

Administrative practice and procedure, Flood insurance, Reporting and recordkeeping requirements.

Accordingly, 44 CFR part 67 is amended as follows:

PART 67—[AMENDED]

■ 1. The authority citation for part 67 continues to read as follows:

Authority: 42 U.S.C. 4001 *et seq.;* Reorganization Plan No. 3 of 1978, 3 CFR, 1978 Comp., p. 329; E.O. 12127, 44 FR 19367, 3 CFR, 1979 Comp., p. 376.

§ 67.11 [Amended]

■ 2. The tables published under the authority of § 67.11 are amended as follows:

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Volusia County, Florida, and Incorporated Areas Docket No.: FEMA–B–1131			
Angela Lake	Entire shoreline	*28	City of Deltona.
Dupont Lake	Entire shoreline	*28	City of Deltona.
Lake Butler	Entire shoreline	*28	City of Deltona, Unincorporated Areas of Volusia County.
Louise Lake	Entire shoreline	*28	City of Deltona.
Outlook Lake	Entire shoreline	*57	City of Deltona.
Ponding Area 5	Ponding area bounded by I–4 to the north and west, North Firwood Drive to the south, and North Normandy Boulevard to the east.	*44	City of Deltona.
Ponding Area 6	Ponding area bounded by Graves Avenue to the north, North Normandy Boulevard to the west, North Firwood Drive to the south, and West Seagate Drive to the east.	*74	City of Deltona.
Ponding Area 7	Ponding area bounded by Graves Avenue to the north, North Normandy Boulevard to the west, North Firwood Drive to the south, and West Seagate Drive to the east.	*74	City of Deltona.
Ponding Area 8	Ponding area bounded by I–4 to the north and west, North Gloria Drive to the south, and East Annapolis Drive to the east.	*36	City of Deltona.
Ponding Area 9	Ponding area bounded by Graves Avenue to the north, North Normandy Boulevard to the west, Vicksburg Street to the south, and Utility Driveway to the east.	*79	City of Deltona.
Ponding Area 10	Ponding area bounded by North Firwood Drive to the north, North Normandy Boulevard to the west, Arlene Drive to the south, and East Firwood Drive to the east.	*79	City of Deltona.
Ponding Area 11	Ponding area bounded by Graves Avenue to the north, North Normandy Boulevard to the west, Vicksburg Street to the south, and Utility Driveway to the east.	*79	City of Deltona.
Ponding Area 12	Ponding area bounded by Flagler Street to the north, I–4 to the west, South Annapolis Drive to the south, and East Annapolis Drive to the east.	*36	City of Deltona.
Ponding Area 13	Ponding area bounded by Arlene Drive to the north, North Normandy Boulevard to the west and south, and Fitzpatrick Terrace to the east.	*65	City of Deltona.
Ponding Area 14	Ponding area bounded by North Fairbanks Drive to the north, East Firwood Drive to the west, Arlene Drive to the south, and Banbury Avenue to the east.	*88	City of Deltona.
Ponding Area 15	Ponding area bounded by I–4 to the north and west, Sullivan Street to the south, and Galveston Avenue to the east.	*32	City of Deltona.
Ponding Area 16	Ponding area bounded by North Gloria Drive to the north, Galveston Avenue to the west, Antelope Drive to the south, and East Gloria Drive to the east.	*38	City of Deltona.
Ponding Area 17	Ponding area bounded by Applegate Terrace to the north, East Gloria Drive to the west and south, and North Normandy Boulevard to the east.	*51	City of Deltona.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Ponding Area 18	Ponding area bounded by I–4 to the north and west, Sullivan Street to the south, and Galveston Avenue to the east.	*40	City of Deltona.
Ponding Area 19	Ponding area bounded by Geraldine Drive to the north and east, Apricot Drive to the west, and Gondolier Terrace to the south.	*38	City of Deltona.
Ponding Area 20	Ponding area bounded by Gallagher Avenue to the north and west, Sullivan Street to the south, and East Gloria Drive to the east.	*51	City of Deltona.
Ponding Area 21	Ponding area bounded by I–4 to the north and west, Rockford Street to the south, and West Parkton Drive to the east.	*34	City of Deltona.
Ponding Area 22	Ponding area bounded by I–4 to the north and west, Sullivan Street to the south, and Galveston Avenue to the east.	*40	City of Deltona.
Ponding Area 23	Ponding area bounded by Gallagher Avenue to the north and west, Sullivan Street to the south, and East Gloria Drive to the east.	*43	City of Deltona.
Ponding Area 24	Ponding area bounded by Sullivan Street to the north, East Parkton Drive to the west, South Anchor Drive to the south, and East Anchor Drive to the east.	*43	City of Deltona.
Ponding Area 25	Ponding area bounded by Gainsboro Street to the north, East Anchor Drive to the west, Elwood Street to the south, and Dupont Court to the east.	*53	City of Deltona.
Ponding Area 26	Ponding area bounded by North Goodrich Drive to the north, Escobar Avenue to the west, South Glancy Drive to the south, and East Glancy Drive to the east.	*37	City of Deltona.
Ponding Area 27	Ponding area bounded by Leland Drive to the north and west, Fisher Drive to the south, and Providence Boulevard to the east.	*31	City of Deltona.
Ponding Area 28	Ponding area bounded by Providence Boulevard to the north and west, Grapewood Street to the south, and Chestnut Court to the east.	*39	City of Deltona.
Ponding Area 29	Ponding area bounded by Leland Drive to the north, Coventry Estates Boulevard to the west, Debary Avenue to the south, and Monarco Avenue to the east.	*34	City of Deltona, Unincorporated Areas of Volusia County.
Ponding Area 30	Ponding area bounded by Beckwith Street to the north, Coachman Drive to the west, Bentley Court to the south, and Courtland Boulevard to the east.	*47	City of Deltona.
Ponding Area 31	Ponding area bounded by Captain Drive to the north, Parma Drive to the west, Lake Helen Osteen Road to the south, and Snow Drive to the east.	*28	City of Deltona.
Ponding Area 32	Ponding area bounded by Yorkshire Drive to the north and west, Catalina Boulevard to the south, and Lake Helen Osteen Road to the east.	*36	City of Deltona.
Ponding Area 33	Ponding area bounded by Coventry Street to the north, Courtland Boulevard to the west, Riverhead Drive to the south, and Jewel Avenue to the east.	*51	City of Deltona.
Ponding Area 34	Ponding area bounded by Riverhead Drive to the north, Courtland Boulevard to the west, Laredo Drive to the south, and East Dorchester Drive to the east.	*51	City of Deltona, Unincorporated Areas of Volusia County.
Ponding Area 35	Ponding area bounded by Elkcam Boulevard to the north, East Cooper Drive to the west, Beechdale Drive to the south, and Eden Drive to the east.	*28	City of Deltona.
Ponding Area 36	Ponding area bounded by Tivoli Drive to the north, Lydia Drive to the west, Fergason Avenue to the south, and Providence Boulevard to the east.	*49	City of Deltona.
Ponding Area 37	Ponding area bounded by Lake Helen Osteen Road to the north, Center Road to the west, Howland Boulevard to the south, and Austin Avenue to the east.	*28	City of Deltona.
Ponding Area 38	Ponding area bounded by Newmark Drive to the north, Cofield Drive to the west, Conyers Court to the south, and Amboy Drive to the east.	*28	City of Deltona.
Ponding Area 39	Ponding area bounded by Clewiston Street to the north, Etta Circle to the west, Hallow Drive to the south, and Courtland Boulevard to the east.	*23	City of Deltona.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Ponding Area 40	Ponding area bounded by Montcalm Street to the north, Gage Avenue to the west, Goldenhills Street to the south, and Clarion Circle to the east.	*26	City of Deltona.
Ponding Area 41	Ponding area bounded by Alexander Avenue to the north and east, Providence Boulevard to the west, and Grapewood Street to the south.	*69	City of Deltona.
Ponding Area 42	Ponding area bounded by Doyle Road to the north, Braddock Road to the west and south, and West Harbor Drive to the east.	*42	City of Deltona, Unincorporated Areas of Volusia County.
Ponding Area 43	Ponding area bounded by Lake Helen Osteen Road to the north and east, Sixma Road to the west, and Yorkshire Drive to the south.	*34	City of Deltona, Unincorporated Areas of Volusia County.
Ponding in the vicinity of Angela Lake, Dupont Lake, Lake Butler, Louise Lake, and Theresa Lake.	Ponding area bounded by Howland Boulevard to the north and east, Providence Boulevard to the west, and Doyle Road to the south.	*28	City of Deltona, Unincorporated Areas of Volusia County.
Theresa Lake	Entire shoreline	*28	City of Deltona.
Three Island Lakes	Entire shoreline	*28	City of Deltona, Unincorporated Areas of Volusia County.
Trout Lake	Entire shoreline	*26	City of Deltona.

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

City of Deltona

Maps are available for inspection at the Department of Developmental Services, 777 Deltona Boulevard, Deltona, FL 32725.

Unincorporated Areas of Volusia County

Maps are available for inspection at the Volusia County Office of Growth Management, 123 West Indiana Avenue, DeLand, FL 32720.

Woodbury County, Iowa, and Incorporated Areas
Docket No.: FEMA–B–1098

Flooding source(s)	Location of referenced elevation	Elevation	Communities affected
Little Sioux River	Approximately 0.95 mile downstream of 220th Street	+1100	Unincorporated Areas of Woodbury County.
	Approximately 1.09 miles upstream of 220th Street	+1105	
Missouri River	Approximately 900 feet upstream of the Monona County boundary.	+1064	City of Sioux City, Unincorporated Areas of Woodbury County, Winnebago Indian Tribe.
	Approximately 500 feet downstream of the Dakota County boundary.	+1090	
Perry Creek	Approximately 150 feet upstream of 6th Street	+1108	City of Sioux City.
	Approximately 225 feet upstream of Country Club Boulevard.	+1144	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

City of Sioux City

Maps are available for inspection at 405 6th Street, Sioux City, IA 51101.

Unincorporated Areas of Woodbury County

Maps are available for inspection at 620 Douglas Street, 6th Floor, Sioux City, IA 51101.

Winnebago Indian Tribe

Maps are available for inspection at 100 Bluff Street, Winnebago, NE 68071.

Shawnee County, Kansas, and Incorporated Areas
Docket No.: FEMA–B–1087

Flooding source(s)	Location of referenced elevation	Elevation	Communities affected
Butcher Creek	Just upstream of I–470	+977	City of Topeka, Unincorporated Areas of Shawnee County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 1,565 feet upstream of Southeast 45th Street.	+994	
Colly Creek	At the confluence with South Branch Shunganunga Creek	+952	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 300 feet upstream of Southwest Gage Boulevard.	+988	
Cross Creek	At the confluence with Kansas Creek	+919	City of Rossville, Unincorporated Areas of Shawnee County.
	Approximately 0.6 mile upstream of U.S. Route 24	+932	
Deer Creek	At the confluence with Shunganunga Creek	+882	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 100 feet downstream of Southeast 45th Street.	+967	
Elevation Tributary	At the confluence with Shunganunga Creek	+976	City of Topeka.
	At the confluence with Southwest Branch Elevation Creek	+986	
Indian Hills Tributary	At the confluence with Shunganunga Creek	+958	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 580 feet upstream of Southwest Urish Road.	+998	
Shunganunga Creek	At the confluence with the Kansas River	+873	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 280 feet upstream of Indian Hills Road	+1013	
Soldier Creek	At the confluence with the Kansas River	+880	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 0.6 mile upstream of Northwest Menoken Road.	+901	
South Branch Shunganunga Creek.	At the confluence with Shunganunga Creek	+917	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 250 feet upstream of Burlingame Road	+953	
Southeast Branch Elevation Creek.	At the confluence with Elevation Tributary	+986	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 0.7 mile upstream of Southwest Wanamaker Road.	+1031	
Southwest Branch Elevation Creek.	At the confluence with Elevation Tributary	+986	City of Topeka.
	Approximately 0.5 mile upstream of Southwest 41st Street	+1031	
Wanamaker Main Branch	At the confluence with the Kansas River	+885	City of Topeka, Unincorporated Areas of Shawnee County.
	Approximately 300 feet upstream of Southwest Robinson Avenue.	+956	
Wanamaker Northeast Branch	At the confluence with Wanamaker Main Branch	+937	City of Topeka.
	Approximately 0.4 mile upstream of Southwest Robinson Avenue.	+947	
West Fork Butcher Creek	At the confluence with Butcher Creek	+943	City of Topeka.
	Approximately 1,250 feet upstream of Southeast 45th Street.	+1000	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

City of Rossville

Maps are available for inspection at City Hall, 438 Main Street, Rossville, KS 66533.

City of Topeka

Maps are available for inspection at the Engineering Division, 620 Southeast Madison Street, Topeka, KS 66603.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Unincorporated Areas of Shawnee County			
Maps are available for inspection at the County Engineer's Office, 1515 Northwest Saline Street, Topeka, KS 66618.			
Shiawassee County, Michigan (All Jurisdictions) **Docket No.: FEMA–B–1095**			
Holly Drain	Approximately 1,470 feet upstream of Maple Street	+764	Village of Vernon.
	Approximately 1,500 feet upstream of Maple Street	+764	
Shiawassee River	Approximately 5,780 feet upstream of North Shiawassee Street.	+741	Charter Township of Caledonia, Township of Vernon, Village of Vernon.
	Approximately 520 feet upstream of Washington Avenue	+762	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

Charter Township of Caledonia

Maps are available for inspection at the Caledonia Township Hall, 135 North State Street, Owosso, MI 48867.

Township of Vernon

Maps are available for inspection at the Vernon Township Hall, 6801 South Durand Road, Durand, MI 48429.

Village of Vernon

Maps are available for inspection at the Vernon Village Hall, 120 Main Street, Vernon, MI 48476.

Cape Girardeau County, Missouri, and Incorporated Areas **Docket No.: FEMA–B–1089**			
Apple Creek	Approximately 1,010 feet downstream of U.S. Route 61	+399	Village of Old Appleton.
	Approximately 200 feet upstream of U.S. Route 61	+403	
Goose Creek	Approximately 0.4 mile downstream of County Road 302	+475	Unincorporated Areas of Cape Girardeau County.
	Approximately 0.5 mile upstream of County Road 302	+503	
Goose Creek East Fork	Just upstream of the confluence with Goose Creek	+485	Unincorporated Areas of Cape Girardeau County.
	Approximately 1,490 feet upstream of the confluence with Goose Creek.	+503	
Hubble Creek	Approximately 0.5 mile upstream of Sunset Hills Drive	+449	Unincorporated Areas of Cape Girardeau County.
	Approximately 100 feet upstream of the southbound ramp of I–55.	+508	
Mississippi River	Approximately 4.6 miles downstream of State Route 140	+348	City of Cape Girardeau, Unincorporated Areas of Cape Girardeau County.
	Approximately 24.6 miles upstream of State Route 140	+368	
Ramsey Branch	Approximately 100 feet upstream of I–55	+355	City of Cape Girardeau, Unincorporated Areas of Cape Girardeau County.
	Approximately 1.5 miles upstream of County Road 314	+474	
Rocky Branch	Approximately 200 feet upstream of North Farmington Road.	+470	Unincorporated Areas of Cape Girardeau County.
	Approximately 0.6 mile upstream of North Farmington Road.	+488	
Rocky Branch West Fork	Just upstream of the confluence with Rocky Branch	+410	City of Jackson, Unincorporated Areas of Cape Girardeau County.
	Approximately 260 feet upstream of Old Toll Road	+446	
Unnamed Tributary to Hubble Creek (backwater effects from Hubble Creek).	Approximately 500 feet upstream from the confluence with Hubble Creek.	+441	Unincorporated Areas of Cape Girardeau County.
	Approximately 635 feet upstream from the confluence with Hubble Creek.	+441	
Veterans Fork	Approximately 1,775 feet downstream of State Highway K	+395	City of Cape Girardeau, Unincorporated Areas of Cape Girardeau County.
	Approximately 1,575 feet upstream of County Road 314	+453	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Williams Creek	Just upstream of County Road 318	+404	City of Jackson, Unincorporated Areas of Cape Girardeau County.
	Approximately 1,003 feet upstream of Bainbridge Road	+441	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

City of Cape Girardeau
Maps are available for inspection at City Hall, 401 Independence Street, Cape Girardeau, MO 63703.

City of Jackson
Maps are available for inspection at City Hall, 101 Court Street, Jackson, MO 63755.

Unincorporated Areas of Cape Girardeau County
Maps are available for inspection at the Cape Girardeau County Courthouse, 1 Barton Square, Jackson, MO 63755.

Village of Old Appleton
Maps are available for inspection at the Cape Girardeau County Courthouse, 1 Barton Square, Jackson, MO 63755.

Sussex County, New Jersey (All Jurisdictions)
Docket No.: FEMA–B–1100 and FEMA–B–1133

Culvers Creek	At the confluence with Dry Brook	+528	Township of Frankford.
	At the upstream corporate limit of the Township of Frankford.	+645	
Delaware River	At the Warren County boundary	+352	Township of Montague, Township of Sandyston, Township of Walpack.
	At the New York State boundary	+426	
Dry Brook	At the upstream side of the State Route 206 culvert	+509	Borough of Branchville, Township of Frankford.
	Approximately 675 feet upstream of Wantage Avenue (County Route 519).	+575	
Lake Hopatcong	Entire shoreline within community	+925	Borough of Hopatcong.
Lake Mohawk	Entire shoreline within community	+730	Township of Byram.
Lubbers Run	At the downstream corporate limit of the Borough of Hopatcong.	+733	Borough of Hopatcong.
	Approximately 3,540 feet upstream of County Road 605	+809	
Lubbers Run	Approximately 2,620 feet downstream of Mansfield Drive	+710	Township of Byram.
	Approximately 140 feet upstream of Mansfield Drive	+713	
Musconetcong River	At the downstream corporate limit of the Borough of Hopatcong.	+870	Borough of Hopatcong.
	Approximately 2,530 feet upstream of the downstream corporate limit of the Borough of Hopatcong.	+876	
Paulins Kill	At the Township of Hampton corporate limit	+502	Township of Frankford.
	Approximately 200 feet downstream of Decker Road	+502	
Pequest River	Approximately 380 feet downstream of County Road 618 (at the Township of Andover corporate limit).	+583	Township of Fredon.
	Approximately 400 feet upstream of County Road 618 (at the Township of Andover corporate limit).	+584	
Unnamed Tributary to Paulins Kill.	Approximately 300 feet downstream of U.S. Route 206	+502	Township of Hampton.
	Approximately 20 feet downstream of U.S. Route 206	+502	
Wallkill River	Approximately 315 feet upstream of County Route 565 (at the Township of Vernon corporate limit).	+393	Township of Hardyston.
	Approximately 320 feet downstream of Scott Road (at the Borough of Franklin corporate limit).	+403	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

Borough of Branchville
Maps are available for inspection at the Municipal Building, 5 Main Street, Branchville, NJ 07826.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected

Borough of Hopatcong
Maps are available for inspection at the Municipal Building, 111 River Styx Road, Hopatcong, NJ 07843.
Township of Byram
Maps are available for inspection at the Byram Township Municipal Building, 10 Mansfield Drive, Stanhope, NJ 07874.
Township of Frankford
Maps are available for inspection at the Frankford Township Municipal Building, 151 State Highway 206, August, NJ 07822.
Township of Fredon
Maps are available for inspection at the Fredon Township Municipal Building, 443 Route 94, Newton, NJ 07860.
Township of Hampton
Maps are available for inspection at the Hampton Township Municipal Building, 1 Rumsey Way, Newton, NJ 07860.
Township of Hardyston
Maps are available for inspection at the Municipal Building, 149 Wheatsworth Road, Suite A, Hardyston, NJ 07419.
Township of Montague
Maps are available for inspection at the Municipal Building, 277 Clove Road, Montague, NJ 07827.
Township of Sandyston
Maps are available for inspection at the Municipal Building, 133 County Route 645, Sandyston, NJ 07827.
Township of Walpack
Maps are available for inspection at the Walpack Township Municipal Building, 9 Main Street, Walpack Center, NJ 07881.

Warren County, New Jersey (All Jurisdictions)
Docket No.: FEMA–B–1098

Buckhorn Creek	At the confluence with the Delaware River	+226	Township of Harmony.
	Approximately 850 feet upstream of Hutchinson Station Road.	+226	
Delaware River	Approximately 150 feet upstream of Riegelsville Bridge	+161	Town of Belvidere, Town of Phillipsburg, Township of Hardwick, Township of Harmony, Township of Knowlton, Township of Lopatcong, Township of Pohatcong, Township of White.
	At the Sussex County boundary	+352	
Lopatcong Creek	At the confluence with the Delaware River	+186	Town of Phillipsburg.
	Approximately 450 feet upstream of Waste Water Treatment Facility Driveway.	+186	
Pequest River	At the confluence with the Delaware River	+256	Town of Belvidere.
	Approximately 100 feet downstream of Orchard Street	+284	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

Town of Belvidere
Maps are available for inspection at the Municipal Building, 691 Water Street, Belvidere, NJ 07823.
Town of Phillipsburg
Maps are available for inspection at the Municipal Building, 675 Corliss Avenue, Phillipsburg, NJ 08865.
Township of Hardwick
Maps are available for inspection at the Municipal Building, 40 Spring Valley Road, Hardwick, NJ 07825.
Township of Harmony
Maps are available for inspection at the Harmony Township Municipal Building, 3003 Belvidere Road, Phillipsburg, NJ 08865.
Township of Knowlton
Maps are available for inspection at the Knowlton Township Municipal Building, 628 Route 94, Columbia, NJ 07832.
Township of Lopatcong
Maps are available for inspection at the Lopatcong Township Municipal Building, 232 South 3rd Street, Phillipsburg, NJ 08865.
Township of Pohatcong
Maps are available for inspection at the Pohatcong Township Municipal Building, 50 Municipal Drive, Phillipsburg, NJ 08865.
Township of White
Maps are available for inspection at the White Township Municipal Building, 555 County Road 519, Belvidere, NJ 07823.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Stark County, Ohio, and Incorporated Areas Docket No.: FEMA–B–1098			
Broad-Monter Creek	At the upstream side of Ravenna Avenue	+1110	Unincorporated Areas of Stark County.
	Approximately 650 feet upstream of Ravenna Avenue	+1110	
	Approximately 320 feet downstream of Meese Road	+1157	
	At the downstream side of Meese Road	+1161	
Chatham Ditch	Approximately 900 feet upstream of 7th Street	+1100	City of North Canton.
	Approximately 950 feet downstream of Holl Road	+1121	
Clays Ditch	Approximately 1,300 feet upstream of Roanoke Street	+1031	Unincorporated Areas of Stark County.
	Approximately 220 feet upstream of Knight Street	+1039	
East Branch Nimishillen Creek	Approximately 140 feet downstream of Beck Avenue	+1081	City of Louisville, Unincorporated Areas of Stark County.
	At the downstream side of Nickel Plate Avenue	+1109	
East Branch Nimishillen Creek (backwater effects).	Approximately 650 feet upstream of the confluence with East Branch Nimishillen Creek and East Branch Nimishillen Creek Diversion.	+1050	City of Canton.
	Approximately 1,350 feet upstream of the confluence with East Branch Nimishillen Creek and East Branch Nimishillen Creek Diversion.	+1050	
Mahoning River	Approximately 1,400 feet downstream of Union Avenue	+1032	City of Alliance, Unincorporated Areas of Stark County.
	Approximately 0.86 mile upstream of Webb Avenue	+1046	
Mahoning River Overflow	At the confluence with the Mahoning River	+1045	City of Alliance, Unincorporated Areas of Stark County.
	At the divergence from the Mahoning River	+1046	
McDowell Ditch	Approximately 140 feet upstream of Guilford Avenue	+1045	City of Canton, City of North Canton, Unincorporated Areas of Stark County.
	At the confluence with Zimber Ditch	+1062	
McDowell Ditch Overflow 1 (formerly McDowell Ditch Diversion Channel).	At the downstream side of I–77	+1051	Unincorporated Areas of Stark County.
	At the upstream side of I–77	+1053	
McDowell Ditch Overflow 2	At the confluence with McDowell Ditch Overflow 1	+1054	City of Canton, Unincorporated Areas of Stark County.
	At the divergence from McDowell Ditch	+1055	
Metzger Ditch	Approximately 160 feet downstream of Cain Street (at the Summit County boundary).	+1107	Unincorporated Areas of Stark County.
	Approximately 1.18 miles upstream of Lake Center Street	+1124	
Middle Tributary	At the confluence with North Chapel Creek	+1108	City of Louisville.
	At the downstream side of Atlantic Boulevard (U.S. Route 62).	+1148	
North Chapel Creek	At the upstream side of Frana Clara Street	+1105	City of Louisville, Unincorporated Areas of Stark County.
	At the downstream side of Atlantic Boulevard (U.S. Route 62).	+1144	
Plum Creek	Approximately 0.82 mile downstream of Manchester Avenue (State Route 93).	+947	City of Canal Fulton, Unincorporated Areas of Stark County.
	At the downstream side of Akron Avenue	+1012	
Unnamed Tributary to East Branch Nimishillen Creek.	At the confluence with East Branch Nimishillen Creek	+1085	City of Louisville, Unincorporated Areas of Stark County.
	At the downstream side of Georgetown Street	+1105	
West Branch Nimishillen Creek	Approximately 190 feet downstream of I–77	+1043	City of Canton, City of North Canton, Unincorporated Areas of Stark County.
	Approximately 700 feet downstream of Hoover Avenue	+1155	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
West Branch Nimishillen Creek Overflow.	At the downstream side of Midway Street	+1126	Unincorporated Areas of Stark County.
	Approximately 400 feet upstream of Midway Street	+1130	
West Branch Nimishillen Creek Tributary 1.	At the confluence with West Branch Nimishillen Creek	+1090	Unincorporated Areas of Stark County.
	At the upstream side of State Street	+1140	
West Sippo Creek	At the downstream side of Deermont Avenue	+995	City of Massillon, Unincorporated Areas of Stark County.
	At the downstream side of Manchester Avenue (State Route 93).	+1034	
Zimber Ditch Tributary 1	Approximately 0.45 mile upstream of Beech Hill Road (at the Summit County Boundary).	+1107	Unincorporated Areas of Stark County.
	Approximately 1,080 feet upstream of Cleveland Avenue	+1164	
Zimber Ditch Tributary 1A	At the confluence with Zimber Ditch Tributary 1	+1122	Unincorporated Areas of Stark County.
	Approximately 0.39 mile upstream of Burkey Road	+1156	

* National Geodetic Vertical Datum.
+ North American Vertical Datum.
# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

City of Alliance
Maps are available for inspection at the City Office, 504 East Main Street, Alliance, OH 44601.

City of Canal Fulton
Maps are available for inspection at City Hall, 155 East Market Street, Canal Fulton, OH 44614.

City of Canton
Maps are available for inspection at the City Offices, 424 Market Avenue North, Canton, OH 44702.

City of Louisville
Maps are available for inspection at City Hall, 215 South Mill Street, Louisville, OH 44641.

City of Massillon
Maps are available for inspection at the Municipal Government Annex, 151 Lincolnway East, Massillon, OH 44646.

City of North Canton
Maps are available for inspection at the Engineering Office, 220 West Maple Street, North Canton, OH 44720.

Unincorporated Areas of Stark County
Maps are available for inspection at the Stark County Building Department, 110 Central Plaza South, Canton, OH 44702.

Anderson County, South Carolina, and Incorporated Areas
Docket No.: FEMA–B–1115

Bailey Creek	Approximately 600 feet upstream of the confluence with Cox Creek.	+673	City of Anderson, Unincorporated Areas of Anderson County.
	Approximately 1.4 miles upstream of Simpson Road	+732	
Bear Creek	At the confluence with the Rocky River	+556	Unincorporated Areas of Anderson County.
	Approximately 1.7 miles upstream of Due West Highway	+714	
Beaver Creek	At the confluence with the Rocky River	+571	Unincorporated Areas of Anderson County.
	Approximately 2,300 feet upstream of the confluence with Beaver Creek Tributary 15.	+770	
Beaver Creek Tributary 1	At the confluence with Beaver Creek	+572	Unincorporated Areas of Anderson County.
	Approximately 1,100 feet upstream of Mimosa Trail	+585	
Beaver Creek Tributary 12	Approximately 380 feet upstream of the confluence with Beaver Creek.	+690	Unincorporated Areas of Anderson County.
	Approximately 2,180 feet upstream of Kaye Drive	+738	
Beaver Creek Tributary 13	Approximately 270 feet upstream of the confluence with Beaver Creek.	+704	Unincorporated Areas of Anderson County.
	Approximately 1,050 feet upstream of Keys Street	+789	
Beaver Creek Tributary 14	Approximately 210 feet upstream of the confluence with Beaver Creek.	+704	Unincorporated Areas of Anderson County.
	Approximately 650 feet upstream of Winfield Drive	+776	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Beaver Creek Tributary 15	At the confluence with Beaver Creek	+744	Unincorporated Areas of Anderson County.
	Approximately 3,010 feet upstream of the confluence with Beaver Creek.	+764	
Beaverdam Creek A	At the confluence with the Rocky River	+690	Unincorporated Areas of Anderson County.
	Approximately 3,480 feet upstream of Welcome Road	+766	
Beaverdam Creek A Tributary 15.	At the confluence with Beaverdam Creek A	+757	Unincorporated Areas of Anderson County.
	Approximately 3,530 feet upstream of the confluence with Beaverdam Creek A.	+774	
Beaverdam Creek B Tributary 3	Approximately 260 feet downstream of I–85	+680	Unincorporated Areas of Anderson County.
	Approximately 2,860 feet upstream of I–85	+717	
Big Brushy Creek	Approximately 500 feet upstream of the confluence with the Saluda River.	+777	Unincorporated Areas of Anderson County.
	At the Pickens County boundary	+901	
Big Brushy Creek Tributary 17	At the confluence with Big Brushy Creek	+789	Unincorporated Areas of Anderson County.
	Approximately 4,330 feet upstream of the confluence with Big Brushy Creek.	+809	
Big Brushy Creek Tributary 23	At the confluence with Big Brushy Creek	+782	Unincorporated Areas of Anderson County.
	Approximately 550 feet upstream of Blossom Branch Road.	+818	
Big Brushy Creek Tributary 9	At the confluence with Big Brushy Creek	+800	Unincorporated Areas of Anderson County.
	Approximately 450 feet upstream of Cater Drive	+810	
Big Creek	At the confluence with the Saluda River	+647	Town of Williamston, Unincorporated Areas of Anderson County.
	Approximately 2,060 feet upstream of U.S. Route 29	+871	
Big Creek Tributary 13	At the confluence with Big Creek	+695	Unincorporated Areas of Anderson County.
	Approximately 2,640 feet upstream of the confluence with Big Creek.	+716	
Big Garvin Creek	At the confluence with Three and Twenty Creek	+726	Unincorporated Areas of Anderson County.
	Approximately 1,950 feet upstream of Central Road	+788	
Big Garvin Creek Tributary 3	At the confluence with Big Garvin Creek	+745	Unincorporated Areas of Anderson County.
	Approximately 630 feet upstream of Bishops Branch Road	+767	
Big Generostee Creek	Approximately 600 feet upstream of the confluence with Lazy Branch.	+613	Unincorporated Areas of Anderson County.
	Just downstream of Michelin Boulevard	+664	
Big Generostee Creek Tributary 15.	At the confluence with Big Generostee Creek	+624	Unincorporated Areas of Anderson County.
	Approximately 1,860 feet upstream of the confluence with Big Generostee Creek.	+644	
Big Generostee Creek Tributary 17.	At the confluence with Big Generostee Creek	+627	Unincorporated Areas of Anderson County.
	Approximately 1,980 feet upstream of the confluence with Big Generostee Creek.	+644	
Big Generostee Creek Tributary 20.	At the confluence with Big Generostee Creek	+634	Unincorporated Areas of Anderson County.
	Approximately 2,160 feet upstream of the confluence with Big Generostee Creek.	+661	
Big Generostee Creek Tributary 22.	At the confluence with Big Generostee Creek	+641	Unincorporated Areas of Anderson County.
	Approximately 4,180 feet upstream of the confluence with Big Generostee Creek.	+685	
Big Generostee Creek Tributary 28.	Approximately 480 feet upstream of the confluence with Big Generostee Creek.	+670	Unincorporated Areas of Anderson County.
	Approximately 490 feet upstream of the railroad	+787	
Big Generostee Creek Tributary 30.	Approximately 380 feet upstream of the confluence with Big Generostee Creek.	+679	Unincorporated Areas of Anderson County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 2,540 feet upstream of the confluence with Big Generostee Creek.	+690	
Big Generostee Creek Tributary 31.	Approximately 1,000 feet upstream of the confluence with Big Generostee Creek.	+682	Unincorporated Areas of Anderson County.
	Approximately 2,130 feet upstream of West Shockley Fry Road.	+794	
Big Generostee Creek Tributary 32.	Approximately 960 feet upstream of the confluence with Big Generostee Creek.	+683	Unincorporated Areas of Anderson County.
	Approximately 100 feet upstream of New Pond Road	+773	
Broad Mouth Creek	At the Abbeville County boundary	+593	Unincorporated Areas of Anderson County.
	Approximately 2,700 feet upstream of State Highway 247	+778	
Broad Mouth Creek Tributary 11.	At the confluence with Broad Mouth Creek	+648	Unincorporated Areas of Anderson County.
	Approximately 1,330 feet upstream of Nalley Road	+667	
Broad Mouth Creek Tributary 11.1.	At the confluence with Broad Mouth Creek Tributary 11	+651	Unincorporated Areas of Anderson County.
	Approximately 1,380 feet upstream of the confluence with Broad Mouth Creek Tributary 11.	+664	
Broadway Creek	At the confluence with the Rocky River	+597	Unincorporated Areas of Anderson County.
	Approximately 300 feet downstream of Broadway School Road.	+672	
Brushy Creek	At the confluence with Big Brushy Creek	+802	Unincorporated Areas of Anderson County.
	At the Pickens County boundary	+877	
Brushy Creek Tributary 7	At the confluence with Big Brushy Creek	+819	Unincorporated Areas of Anderson County.
	Approximately 3,010 feet upstream of Laboone Road	+851	
Camp Creek	Approximately 1,250 feet upstream of Cherokee Road	+801	Town of Williamston.
	Approximately 1,850 feet upstream of Cherokee Road	+805	
Canoe Creek	At the confluence with Little Generostee Creek	+490	Unincorporated Areas of Anderson County.
	Approximately 2.0 miles upstream of Turpin Road	+635	
Canoe Creek Tributary 3	At the confluence with Canoe Creek	+520	Unincorporated Areas of Anderson County.
	Approximately 2,900 feet upstream of Gene Forester Road.	+620	
Canoe Creek Tributary 6	At the confluence with Canoe Creek	+544	Unincorporated Areas of Anderson County.
	Approximately 2,800 feet upstream of Hatchery Road	+626	
Canoe Creek Tributary 6.1	At the confluence with Canoe Creek Tributary 6	+553	Unincorporated Areas of Anderson County.
	Approximately 260 feet upstream of Gray Circle	+588	
Carmel Creek	At the confluence with Three and Twenty Creek	+796	Unincorporated Areas of Anderson County.
	At the Pickens County boundary	+824	
Charles Creek	At the confluence with Three and Twenty Creek	+804	Unincorporated Areas of Anderson County.
	Approximately 1.2 miles upstream of Ridge Road	+867	
Cherokee Creek	Approximately 660 feet upstream of the confluence with Cherokee Creek Tributary 17.	+773	City of Belton, Unincorporated Areas of Anderson County.
	Approximately 970 feet upstream of the confluence with Cherokee Creek Tributary 17.	+793	
Cherokee Creek Tributary 17	At the confluence with Cherokee Creek	+780	City of Belton, Unincorporated Areas of Anderson County.
	Approximately 1,090 feet upstream of Watkins Road	+792	
Corner Creek	Approximately 400 feet upstream of the Abbeville County boundary.	+692	Town of Honea Path, Unincorporated Areas of Anderson County.
	Approximately 150 feet upstream of Oak Drive	+762	
Corner Creek Tributary 2	At the confluence with Corner Creek	+703	Town of Honea Path, Unincorporated Areas of Anderson County.
	Approximately 830 feet upstream of Pinson Drive	+771	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Corner Creek Tributary 4	Approximately 200 feet upstream of the confluence with Corner Creek.	+717	Town of Honea Path.
	Approximately 460 feet upstream of Park Avenue	+740	
Craven Creek	Approximately 400 feet upstream of the confluence with the Saluda River.	+787	Unincorporated Areas of Anderson County.
	Approximately 3,010 feet upstream of Cannon Lane	+795	
Crooked Creek	At the confluence with Little Generostee Creek	+481	Unincorporated Areas of Anderson County.
	Approximately 1.3 miles upstream of Sam Turner Road	+530	
Crooked Creek Tributary 2	At the confluence with Crooked Creek	+497	Unincorporated Areas of Anderson County.
	Approximately 2,170 feet upstream of the confluence with Crooked Creek.	+511	
Cuffie Creek	At the confluence with Three and Twenty Creek	+729	Unincorporated Areas of Anderson County.
	Approximately 2.1 miles upstream of Bishops Branch Road.	+809	
Deep Step Creek	At the confluence with Jordan Creek	+613	Unincorporated Areas of Anderson County.
	Approximately 1,600 feet upstream of the confluence with Jordan Creek.	+623	
Double Branch	At the confluence with Three and Twenty Creek	+758	Unincorporated Areas of Anderson County.
	Approximately 3,220 feet upstream of Burgess Road	+789	
East Beards Creek	At the Abbeville County boundary	+505	Unincorporated Areas of Anderson County.
	Approximately 100 feet upstream of Saxton Gin Road	+726	
East Prong Creek	At the confluence with Little Generostee Creek	+518	Unincorporated Areas of Anderson County.
	Approximately 70 feet downstream of Johnny Long Road	+647	
East Prong Creek Tributary 11	At the confluence with East Prong Creek	+578	Unincorporated Areas of Anderson County.
	Approximately 1,340 feet upstream of Hall Road	+641	
Eighteen Mile Creek	Approximately 1,100 feet upstream of the confluence with the Seneca River.	+663	Town of Pendleton, Unincorporated Areas of Anderson County.
	Approximately 80 feet upstream of Central Road	+709	
Eighteen Mile Creek Tributary 1	At the confluence with Eighteen Mile Creek	+663	Unincorporated Areas of Anderson County.
	Approximately 2,090 feet upstream of the confluence with Eighteen Mile Creek.	+663	
Eighteen Mile Creek Tributary 3	At the confluence with Eighteen Mile Creek	+664	Unincorporated Areas of Anderson County.
	Approximately 2,780 feet upstream of the confluence with Eighteen Mile Creek.	+670	
Eighteen Mile Creek Tributary 4	At the confluence with Eighteen Mile Creek	+665	Unincorporated Areas of Anderson County.
	Approximately 2,410 feet upstream of the confluence with Eighteen Mile Creek.	+678	
Eighteen Mile Creek Tributary 5	At the confluence with Eighteen Mile Creek	+665	Unincorporated Areas of Anderson County.
	Approximately 2,960 feet upstream of the confluence with Eighteen Mile Creek.	+674	
Eighteen Mile Creek Tributary 6	At the confluence with Eighteen Mile Creek	+667	Unincorporated Areas of Anderson County.
	Approximately 2,350 feet upstream of the confluence with Eighteen Mile Creek.	+677	
Eighteen Mile Creek Tributary 7	At the confluence with Eighteen Mile Creek	+667	Unincorporated Areas of Anderson County.
	Approximately 2,060 feet upstream of Fants Grove Circle	+692	
Eighteen Mile Creek Tributary 10.	At the confluence with Eighteen Mile Creek	+671	Unincorporated Areas of Anderson County.
	Approximately 3,710 feet upstream of the confluence with Eighteen Mile Creek.	+734	
Eighteen Mile Creek Tributary 11.	At the confluence with Eighteen Mile Creek	+671	Unincorporated Areas of Anderson County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 1.6 miles upstream of the confluence with Eighteen Mile Creek.	+734	
Eighteen Mile Creek Tributary 12.	At the confluence with Eighteen Mile Creek	+674	Unincorporated Areas of Anderson County.
	Approximately 3,380 feet upstream of the confluence with Eighteen Mile Creek.	+694	
Eighteen Mile Creek Tributary 13.	At the confluence with Eighteen Mile Creek	+680	Unincorporated Areas of Anderson County.
	Approximately 1,110 feet upstream of Fants Grove Road	+718	
Eighteen Mile Creek Tributary 13.2.	At the confluence with Eighteen Mile Creek Tributary 13	+697	Unincorporated Areas of Anderson County.
	Approximately 3,020 feet upstream of the confluence with Eighteen Mile Creek Tributary 13.	+721	
Eighteen Mile Creek Tributary 18.	At the confluence with Eighteen Mile Creek	+687	Unincorporated Areas of Anderson County.
	Approximately 2,480 feet upstream of West Queen Street	+727	
Eighteen Mile Creek Tributary A	At the confluence with Eighteen Mile Creek	+688	Town of Pendleton, Unincorporated Areas of Anderson County.
	Approximately 4,160 feet upstream of the confluence with Eighteen Mile Creek.	+730	
Eighteen Mile Creek Tributary A Tributary 1.	At the confluence with Eighteen Mile Creek Tributary A	+701	Town of Pendleton.
	Approximately 1.0 mile upstream of the confluence with Eighteen Mile Creek Tributary A.	+768	
Eighteen Mile Creek Tributary B	At the confluence with Eighteen Mile Creek	+695	Town of Pendleton, Unincorporated Areas of Anderson County.
	Approximately 850 feet upstream of Hamberg Street	+738	
Eighteen Mile Creek Tributary B Tributary 2.	At the confluence with Eighteen Mile Creek Tributary B	+738	Town of Pendleton.
	Approximately 1,000 feet upstream of Crenshaw Street	+796	
First Creek	At the confluence with the Rocky River	+549	Unincorporated Areas of Anderson County.
	Approximately 400 feet upstream of First Creek Road	+597	
First Creek Tributary 1	At the confluence with First Creek	+549	Unincorporated Areas of Anderson County.
	Approximately 1,930 feet upstream of the confluence with First Creek.	+557	
Five Mile Creek	At the confluence with Big Generostee Creek	+648	Unincorporated Areas of Anderson County.
	Approximately 2,480 feet upstream of New Prospect Church Road.	+725	
Five Mile Creek Tributary 1	At the confluence with Five Mile Creek	+657	Unincorporated Areas of Anderson County.
	Approximately 1.2 miles upstream of Jones Drive	+744	
Five Mile Creek Tributary 5	At the confluence with Five Mile Creek	+688	Unincorporated Areas of Anderson County.
	Approximately 2,070 feet upstream of Country Meadow Road.	+712	
Five Mile Creek Tributary 9	At the confluence with Five Mile Creek	+718	Unincorporated Areas of Anderson County.
	Approximately 1,130 feet upstream of the confluence with Five Mile Creek.	+741	
Governors Creek	At the confluence with Rocky Creek	+554	Unincorporated Areas of Anderson County.
	Approximately 2,700 feet upstream of Gillespie Road	+624	
Governors Creek Tributary 4	At the confluence with Governors Creek	+583	Unincorporated Areas of Anderson County.
	Approximately 4,550 feet upstream of the confluence with Governors Creek.	+639	
Hartwell Reservoir Tributary	At the confluence with Town Creek A	+663	City of Anderson, Unincorporated Areas of Anderson County.
	Approximately 1,100 feet downstream of Valley Drive	+690	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Hembree Creek	At the confluence with Six and Twenty Creek	+666	City of Anderson, Unincorporated Areas of Anderson County.
	Approximately 3,820 feet upstream of Salem Church Road.	+724	
Hencoop Creek	At the confluence with the Rocky River	+558	Unincorporated Areas of Anderson County.
	Approximately 500 feet upstream of Due West Highway	+615	
Hornbuckle Creek	At the confluence with Big Brushy Creek	+806	Unincorporated Areas of Anderson County.
	Approximately 160 feet upstream of Sitton Hill Road	+829	
Hurricane Creek A	At the confluence with Six and Twenty Creek	+666	Unincorporated Areas of Anderson County.
	Approximately 3,960 feet upstream of I–85	+706	
Hurricane Creek B	At the confluence with the Saluda River	+739	Unincorporated Areas of Anderson County.
	Approximately 2,590 feet upstream of State Highway 17	+849	
Hurricane Creek B Tributary 11	At the confluence with Hurricane Creek B	+817	Unincorporated Areas of Anderson County.
	Approximately 3,350 feet upstream of the confluence with Hurricane Creek B.	+829	
Hurricane Creek B Tributary 7	At the confluence with Hurricane Creek B	+763	Unincorporated Areas of Anderson County.
	Approximately 3,330 feet upstream of the confluence with Hurricane Creek B.	+784	
Hurricane Creek B Tributary 8	At the confluence with Hurricane Creek B	+765	Unincorporated Areas of Anderson County.
	Approximately 1,660 feet upstream of the confluence with Hurricane Creek B.	+772	
Indian Branch	At the confluence with Little Generostee Creek	+551	Unincorporated Areas of Anderson County.
	Approximately 1,400 feet upstream of Pollard Road	+616	
Indian Branch Tributary 3	At the confluence with Indian Branch	+573	Unincorporated Areas of Anderson County.
	Approximately 3,440 feet upstream of the confluence with Indian Branch.	+600	
Jones Creek	At the confluence with Six and Twenty Creek	+675	Unincorporated Areas of Anderson County.
	Approximately 100 feet downstream of Scotts Bridge Road.	+692	
Jones Creek Tributary 1	At the confluence with Jones Creek	+683	Unincorporated Areas of Anderson County.
	Approximately 1,850 feet upstream of I–85	+714	
Jordan Creek	At the confluence with Wilson Creek	+561	Unincorporated Areas of Anderson County.
	Approximately 1,000 feet upstream of Hebron Church Road.	+639	
Jordan Creek Tributary 1	At the confluence with Jordan Creek	+569	Unincorporated Areas of Anderson County.
	Approximately 1,500 feet upstream of Aubrey Hardy Road	+583	
Little Beaverdam Creek	Approximately 600 feet upstream of Hattons Ford Road	+662	Unincorporated Areas of Anderson County.
	At the Oconee County boundary.	+691	
Little Beaverdam Creek A	At the confluence with the Rocky River	+697	Unincorporated Areas of Anderson County.
	Approximately 4,850 feet upstream of Welcome Road	+786	
Little Beaverdam Creek Tributary 2.	At the confluence with Little Beaverdam Creek	+677	Unincorporated Areas of Anderson County.
	Approximately 3,510 feet upstream of the confluence with Little Beaverdam Creek.	+692	
Little Beaverdam Creek Tributary 4.	At the confluence with Little Beaverdam Creek	+669	Unincorporated Areas of Anderson County.
	Approximately 2,200 feet upstream of Gaines Road	+697	
Little Beaverdam Creek Tributary 5.	At the confluence with Little Beaverdam Creek	+668	Unincorporated Areas of Anderson County.
	Approximately 4,470 feet upstream of Fred Dobbins Road	+705	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Little Beaverdam Creek Tributary 6.	At the confluence with Little Beaverdam Creek	+668	Unincorporated Areas of Anderson County.
	Approximately 2,750 feet upstream of Bradberry Road	+710	
Little Beaverdam Creek Tributary 7.	At the confluence with Little Beaverdam Creek	+664	Unincorporated Areas of Anderson County.
	Approximately 2,870 feet upstream of the confluence with Little Beaverdam Creek.	+688	
Little Beaverdam Creek Tributary 8.	At the confluence with Little Beaverdam Creek	+663	Unincorporated Areas of Anderson County.
	Approximately 1,950 feet upstream of Slaton Road	+671	
Little Brushy Creek	At the confluence with Big Brushy Creek	+793	Unincorporated Areas of Anderson County.
	Approximately 1,270 feet upstream of Mountain Springs Road.	+846	
Little Garvin Creek	At the confluence with Big Garvin Creek	+731	Unincorporated Areas of Anderson County.
	Approximately 2,750 feet upstream of Bishops Branch Road.	+764	
Little Generostee Creek	At the Elbert County, Georgia boundary	+480	Town of Starr, Unincorporated Areas of Anderson County.
	Approximately 3,400 feet upstream of Erwin Street	+732	
Little Generostee Creek Tributary 6.	At the confluence with Little Generostee Creek	+648	Unincorporated Areas of Anderson County.
	Approximately 2,600 feet upstream of the confluence with Little Generostee Creek Tributary 6.2.	+732	
Little Generostee Creek Tributary 6.2.	At the confluence with Little Generostee Creek Tributary 6	+707	Unincorporated Areas of Anderson County.
	Approximately 1,600 feet upstream of the confluence with Little Generostee Creek Tributary 6.	+707	
Little Generostee Creek Tributary 8.	At the confluence with Little Generostee Creek	+623	Unincorporated Areas of Anderson County.
	Approximately 2,430 feet upstream of the confluence with Little Generostee Creek.	+655	
Little Generostee Creek Tributary 9.	At the confluence with Little Generostee Creek	+565	Unincorporated Areas of Anderson County.
	Approximately 3,950 feet upstream of the confluence with Little Generostee Creek.	+587	
Long Branch A	At the Abbeville County boundary.	+591	Unincorporated Areas of Anderson County.
	Approximately 2,400 feet upstream of Liberty Road	+618	
Middle Branch Brushy Creek	At the confluence with Big Brushy Creek	+863	Unincorporated Areas of Anderson County.
	At the Pickens County boundary	+875	
Milwee Creek	At the confluence with Three and Twenty Creek	+696	Unincorporated Areas of Anderson County.
	Approximately 1.0 mile upstream of Gentry Road	+868	
Mountain Creek	Approximately 30 feet upstream of the confluence with Big Generostee Creek.	+554	Unincorporated Areas of Anderson County.
	Approximately 1.6 miles upstream of Mountain Church Creek Road.	+724	
Mountain Creek Tributary 11	At the confluence with Mountain Creek	+594	Unincorporated Areas of Anderson County.
	Approximately 1.2 miles upstream of the confluence with Mountain Creek.	+675	
Mountain Creek Tributary 5	At the confluence with Mountain Creek	+572	Unincorporated Areas of Anderson County.
	Approximately 4,500 feet upstream of Carl Baker Road	+617	
Mountain Creek Tributary 6	At the confluence with Mountain Creek	+579	Unincorporated Areas of Anderson County.
	Approximately 3,680 feet upstream of the confluence with Mountain Creek.	+598	
Mountain Creek Tributary 7	At the confluence with Mountain Creek	+580	Unincorporated Areas of Anderson County.
	Approximately 2,350 feet upstream of the confluence with Mountain Creek.	+601	

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
Mountain Creek Tributary 9	At the confluence with Mountain Creek	+586	Unincorporated Areas of Anderson County.
	Approximately 150 feet upstream of Chris De Lane	+652	
Mountain Creek Tributary 9.3	At the confluence with Mountain Creek Tributary 9	+602	Unincorporated Areas of Anderson County.
	Approximately 2,890 feet upstream of Martin Road	+624	
Mountain Creek Tributary 9.5	At the confluence with Mountain Creek Tributary 9	+618	Unincorporated Areas of Anderson County.
	Approximately 1.8 miles upstream of the confluence with Mountain Creek Tributary 9.	+743	
Mountain Creek Tributary 9.8	At the confluence with Mountain Creek Tributary 9	+636	Unincorporated Areas of Anderson County.
	Approximately 2,510 feet upstream of the confluence with Mountain Creek Tributary 9.	+653	
Neals Creek	At the confluence with Broadway Creek	+623	Unincorporated Areas of Anderson County.
	Approximately 900 feet upstream of State Highway 252	+731	
Nesbit Creek	Approximately 290 feet upstream of the confluence with Beaver Creek.	+619	Unincorporated Areas of Anderson County.
	Approximately 1,840 feet upstream of the confluence with Beaver Creek.	+624	
Pea Creek	At the confluence with Broadway Creek	+635	Unincorporated Areas of Anderson County.
	Approximately 1,360 feet upstream of Sherwood Drive	+801	
Pickens Creek	At the confluence with Three and Twenty Creek	+786	Unincorporated Areas of Anderson County.
	Approximately 1,370 feet upstream of Hunt Road	+874	
Pickens Creek Tributary 6	At the confluence with Pickens Creek	+828	Unincorporated Areas of Anderson County.
	Approximately 530 feet upstream of Lake Road	+860	
Richland Creek	At the confluence with Big Generostee Creek	+633	Unincorporated Areas of Anderson County.
	Approximately 1.4 miles upstream of U.S. Route 29	+740	
Richland Creek Tributary 3	At the confluence with Richland Creek	+652	Unincorporated Areas of Anderson County.
	Just downstream of Richland Drive	+652	
Richland Creek Tributary 4	At the confluence with Richland Creek	+670	Unincorporated Areas of Anderson County.
	Approximately 190 feet upstream of Richland Drive	+670	
Rocky Branch	At the confluence with Big Generostee Creek	+638	Unincorporated Areas of Anderson County.
	Approximately 1,630 feet upstream of Strawberry Road	+729	
Rocky River	At the Abbeville County boundary	+548	City of Anderson, Unincorporated Areas of Anderson County.
	Approximately 2,180 feet upstream of the confluence with Little Beaverdam Creek A.	+707	
Rocky River Tributary 1	At the confluence with the Rocky River	+548	Unincorporated Areas of Anderson County.
	Approximately 1.3 miles upstream of the confluence with the Rocky River.	+578	
Rocky River Tributary 18	At the confluence with the Rocky River	+578	Unincorporated Areas of Anderson County.
	Approximately 2,600 feet upstream of Due West Highway	+600	
Rocky River Tributary 20	At the confluence with the Rocky River	+591	Unincorporated Areas of Anderson County.
	Approximately 2,000 feet upstream of Scott Road	+598	
Rocky River Tributary 27	Approximately 400 feet upstream of the confluence with the Rocky River.	+651	Unincorporated Areas of Anderson County.
	Approximately 2,300 feet upstream of the confluence with Rocky River Tributary 27.3.	+776	
Rocky River Tributary 27.3	At the confluence with Rocky River Tributary 27	+751	Unincorporated Areas of Anderson County.
	Approximately 1,410 feet upstream of George Albert Lake Road.	+781	
Rocky River Tributary 28	Approximately 150 feet downstream of Lawrence Road	+652	Unincorporated Areas of Anderson County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 1,000 feet upstream of Lawrence Road	+665	
Salem Creek	Approximately 1,300 feet upstream of the confluence with Six and Twenty Creek.	+660	Unincorporated Areas of Anderson County.
	Approximately 7,900 feet upstream of Centerville Road	+671	
Salem Creek Tributary 4	Approximately 600 feet upstream of the confluence with Salem Creek.	+690	Unincorporated Areas of Anderson County.
	Approximately 590 feet upstream of Quail Ridge Road	+695	
Saluda River	At the Abbeville/Greenville County boundary	+568	Town of Pelzer, Unincorporated Areas of Anderson County.
	Approximately 1,500 feet downstream of the confluence with Saluda River Tributary 41.	+750	
Saluda River Tributary 1	Approximately 250 feet upstream of the confluence with the Saluda River.	+804	Unincorporated Areas of Anderson County.
	Approximately 1.29 miles upstream of Sterling Bridge Road.	+898	
Saluda River Tributary 41	Approximately 100 feet upstream of the confluence with the Saluda River.	+757	Unincorporated Areas of Anderson County.
	Approximately 500 feet upstream of Iler Street	+757	
Saluda River Tributary 42	At the confluence with the Saluda River	+747	Unincorporated Areas of Anderson County.
	Approximately 100 feet upstream of Osteen Hill Road	+761	
Saluda River Tributary 51	At the confluence with the Saluda River	+732	Unincorporated Areas of Anderson County.
	Approximately 1,800 feet upstream of Holiday Street	+784	
Saluda River Tributary 52	At the confluence with the Saluda River	+732	Unincorporated Areas of Anderson County.
	Approximately 1,160 feet upstream of Old River Road	+736	
Saluda River Tributary 62	At the confluence with the Saluda River	+702	Unincorporated Areas of Anderson County.
	Approximately 2,600 feet upstream of the confluence with the Saluda River.	+730	
Saluda River Tributary 103.1	At the confluence with the Saluda River	+639	Unincorporated Areas of Anderson County.
	Approximately 3,600 feet upstream of the confluence with the Saluda River.	+661	
Savannah River	At the Abbeville County boundary	+480	Unincorporated Areas of Anderson County.
	Just downstream of Hartwell Dam	+480	
Savannah River Tributary 23	At the Hart County, Georgia boundary	+480	Unincorporated Areas of Anderson County.
	Approximately 5,000 feet upstream of the Hart County, Georgia boundary.	+490	
Shanklin Creek Tributary A	Approximately 650 feet upstream of the confluence with Shanklin Creek.	+768	Town of Pendleton.
	Approximately 260 feet upstream of East Queen Street	+792	
Silver Brook	Approximately 500 feet upstream of the confluence with the Rocky River.	+664	City of Anderson, Unincorporated Areas of Anderson County.
	Approximately 350 feet upstream of White Street	+742	
Silver Brook Tributary 2	At the confluence with Silver Brook	+703	City of Anderson, Unincorporated Areas of Anderson County.
	Approximately 140 feet upstream of Hall Street	+774	
Six and Twenty Creek	Approximately 4,670 feet downstream of the confluence with Hurricane Creek A.	+665	Unincorporated Areas of Anderson County.
	Approximately 250 feet upstream of the confluence with Six and Twenty Creek Tributary 16.	+668	
Six and Twenty Creek Tributary 10.	At the confluence with Six and Twenty Creek	+667	Unincorporated Areas of Anderson County.
	Approximately 3,610 feet upstream of Manse Jolly Road	+676	
Six and Twenty Creek Tributary 11.	At the confluence with Six and Twenty Creek	+667	Unincorporated Areas of Anderson County.
	Approximately 2,050 feet upstream of the confluence with Six and Twenty Creek.	+676	
Six and Twenty Creek Tributary 12.	At the confluence with Six and Twenty Creek	+667	Unincorporated Areas of Anderson County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 230 feet upstream of Harris Bridge Road	+696	
Six and Twenty Creek Tributary 15.	At the confluence with Six and Twenty Creek	+668	Unincorporated Areas of Anderson County.
	Approximately 3,770 feet upstream of the confluence with Six and Twenty Creek.	+684	
Six and Twenty Creek Tributary 16.	At the confluence with Six and Twenty Creek	+668	Unincorporated Areas of Anderson County.
	Approximately 4,390 feet upstream of Slater Road	+701	
Six and Twenty Creek Tributary 19.	Approximately 30 feet upstream of the confluence with Six and Twenty Creek.	+679	Unincorporated Areas of Anderson County.
	Approximately 1,800 feet upstream of Dalrymple Road	+698	
Three and Twenty Creek	Approximately 160 feet upstream of the confluence with Six and Twenty Creek.	+661	Unincorporated Areas of Anderson County.
	At the Pickens County boundary	+821	
Three and Twenty Creek Tributary 1.	At the confluence with Three and Twenty Creek	+661	Unincorporated Areas of Anderson County.
	Approximately 4,490 feet upstream of the confluence with Three and Twenty Creek.	+686	
Three and Twenty Creek Tributary 3.	At the confluence with Three and Twenty Creek	+663	Unincorporated Areas of Anderson County.
	Approximately 1,040 feet upstream of Rock Creek Road	+688	
Three and Twenty Creek Tributary 5.	At the confluence with Three and Twenty Creek	+665	Unincorporated Areas of Anderson County.
	Approximately 1,480 feet upstream of Hix Road	+706	
Three and Twenty Creek Tributary 5.1.	At the confluence with Three and Twenty Creek Tributary 5.	+665	Unincorporated Areas of Anderson County.
	Approximately 2,410 feet upstream of the confluence with Three and Twenty Creek Tributary 5.	+677	
Three and Twenty Creek Tributary 6.	At the confluence with Three and Twenty Creek	+665	Unincorporated Areas of Anderson County.
	Approximately 2,550 feet upstream of the confluence with Three and Twenty Creek.	+675	
Three and Twenty Creek Tributary 7.	At the confluence with Three and Twenty Creek	+666	Unincorporated Areas of Anderson County.
	Approximately 4,880 feet upstream of Sandy Springs Road.	+685	
Three and Twenty Creek Tributary 8.	At the confluence with Three and Twenty Creek	+668	Unincorporated Areas of Anderson County.
	Approximately 3,900 feet upstream of the confluence with Three and Twenty Creek.	+696	
Three and Twenty Creek Tributary 14.	At the confluence with Three and Twenty Creek	+686	Unincorporated Areas of Anderson County.
	Approximately 400 feet upstream of Lafrance Road	+714	
Three and Twenty Creek Tributary 15.	At the confluence with Three and Twenty Creek	+692	Unincorporated Areas of Anderson County.
	Approximately 1,950 feet upstream of Lafrance Road	+730	
Three and Twenty Creek Tributary 29.	At the confluence with Three and Twenty Creek	+744	Unincorporated Areas of Anderson County.
	Approximately 2,000 feet upstream of Olden Porter Road	+762	
Three and Twenty Creek Tributary 34.	At the confluence with Three and Twenty Creek	+747	Unincorporated Areas of Anderson County.
	Approximately 90 feet upstream of Six and Twenty Road	+789	
Three and Twenty Creek Tributary 43.	At the confluence with Three and Twenty Creek	+778	Unincorporated Areas of Anderson County.
	Approximately 1.0 mile upstream of Slab Bridge Road	+808	
Threemile Creek	At the confluence with Big Generostee Creek	+653	Unincorporated Areas of Anderson County.
	Approximately 390 feet upstream of Michelin Boulevard	+726	
Toney Creek	At the confluence with the Saluda River	+645	Unincorporated Areas of Anderson County.
	Approximately 3,700 feet upstream of Cannon Bottom Road.	+663	
Toney Creek Tributary 1	At the confluence with Toney Creek	+645	Unincorporated Areas of Anderson County.
	Approximately 2,600 feet upstream of Rector Road	+676	
Town Creek A	At the confluence with Six and Twenty Creek	+667	Unincorporated Areas of Anderson County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 140 feet upstream of Foxcroft Way	+685	
Town Creek B	At the confluence with Three and Twenty Creek	+715	Town of Pendleton, Unincorporated Areas of Anderson County.
	Approximately 3,170 feet upstream of Cherry Street	+778	
Town Creek Tributary	At the confluence with Town Creek B	+734	Town of Pendleton, Unincorporated Areas of Anderson County.
	Approximately 4,440 feet upstream of Westinghouse Road.	+783	
Tributary of Eighteen Mile Creek.	At the confluence with Eighteen Mile Creek	+705	Town of Pendleton, Unincorporated Areas of Anderson County.
	Approximately 3,120 feet upstream of the confluence with Eighteen Mile Creek.	+729	
Tributary A of Broad Mouth Creek.	At the confluence with Broad Mouth Creek	+703	City of Belton, Unincorporated Areas of Anderson County.
	Approximately 4,600 feet upstream of Blake Dairy Road	+770	
Tributary A of Broad Mouth Creek Tributary 10.	At the confluence with Tributary A of Broad Mouth Creek	+769	City of Belton, Unincorporated Areas of Anderson County.
	Approximately 1,000 feet upstream of the confluence with Tributary A of Broad Mouth Creek.	+776	
Tributary C of Broad Mouth Creek.	At the confluence with Broad Mouth Creek	+637	Town of Honea Path, Unincorporated Areas of Anderson County.
	Approximately 600 feet upstream of Carolina Avenue	+757	
Tributary C of Broad Mouth Creek Tributary 3.	At the confluence with Tributary C of Broad Mouth Creek	+706	Town of Honea Path.
	Approximately 800 feet upstream of Carter Street	+753	
Tributary C of Broad Mouth Creek Tributary 4.	At the confluence with Tributary C of Broad Mouth Creek	+715	Town of Honea Path.
	Approximately 1,350 feet upstream of Maryland Avenue	+740	
Tugaloo Creek	At the confluence with Beaver Creek	+591	Unincorporated Areas of Anderson County.
	Approximately 3,100 feet upstream of Airline Road	+637	
Unnamed Tributary Beaverdam Creek B Tributary 3.	Approximately 200 feet upstream of the confluence with Beaverdam Creek B Tributary 3.	+662	Unincorporated Areas of Anderson County.
	Approximately 2,400 feet upstream of the confluence with Beaverdam Creek B.	+700	
Unnamed Tributary	Approximately 50 feet upstream of the confluence with Big Generostee Creek.	+528	Unincorporated Areas of Anderson County.
	Approximately 1,780 feet upstream of the confluence with Big Generostee Creek.	+541	
Unnamed Tributary 1	At the Pickens County boundary	+727	Unincorporated Areas of Anderson County.
	Approximately 2,380 feet upstream of the Pickens County boundary.	+749	
Unnamed Tributary of Little Beaverdam Creek Tributary 5.	At the confluence with Little Beaverdam Creek Tributary 5	+678	Unincorporated Areas of Anderson County.
	Approximately 4,000 feet upstream of the confluence with Little Beaverdam Creek Tributary 5.	+712	
Unnamed Tributary of Middle Branch.	At the confluence with Middle Branch Brushy Creek	+872	Unincorporated Areas of Anderson County.
	Approximately 2,240 feet upstream of the confluence with Middle Branch Brushy Creek.	+904	
Weems Creek	Approximately 50 feet upstream of the confluence with Big Generostee Creek.	+508	Unincorporated Areas of Anderson County.
	Approximately 2,000 feet upstream of Lenox Drive	+727	
Weems Creek Tributary 12	At the confluence with Weems Creek	+563	Unincorporated Areas of Anderson County.
	Approximately 3,040 feet upstream of the confluence with Weems Creek.	+582	
Weems Creek Tributary 17	At the confluence with Weems Creek	+527	Unincorporated Areas of Anderson County.

Flooding source(s)	Location of referenced elevation	* Elevation in feet (NGVD) + Elevation in feet (NAVD) # Depth in feet above ground ∧ Elevation in meters (MSL) modified	Communities affected
	Approximately 2,270 feet upstream of the confluence with Weems Creek.	+541	
West Beards Creek	At the Abbeville County boundary	+506	Unincorporated Areas of Anderson County.
	Approximately 1,400 feet upstream of Pine Ridge Road	+667	
West Prong Broad Mouth Creek	At the confluence with Broad Mouth Creek	+742	Unincorporated Areas of Anderson County.
	Approximately 40 feet upstream of State Highway 247	+760	
Whitner Creek	Approximately 70 feet upstream of Lee Street	+746	City of Anderson.
	Approximately 100 feet upstream of Blair Street	+766	
Wilson Creek	At the Abbeville County boundary	+519	Unincorporated Areas of Anderson County.
	Approximately 230 feet upstream of Wesley Court	+775	
Wilson Creek Tributary 17	At the confluence with Wilson Creek	+595	Unincorporated Areas of Anderson County.
	Approximately 3,600 feet upstream of the confluence with Wilson Creek.	+614	
Wilson Creek Tributary 21	At the confluence with Wilson Creek	+628	Unincorporated Areas of Anderson County.
	Approximately 1,650 feet upstream of 1st Avenue	+642	
Wilson Creek Tributary 22	At the confluence with Wilson Creek	+637	Unincorporated Areas of Anderson County.
	Approximately 640 feet upstream of 1st Avenue	+664	
Wilson Creek Tributary 24	At the confluence with Wilson Creek	+650	Unincorporated Areas of Anderson County.
	Approximately 1,750 feet upstream of the confluence of Wilson Creek Tributary 24.5.	+718	
Wilson Creek Tributary 31	At the confluence with Wilson Creek	+689	Unincorporated Areas of Anderson County.
	Approximately 1,800 feet upstream of Farmer Road	+727	

* National Geodetic Vertical Datum.
\+ North American Vertical Datum.
\# Depth in feet above ground.
∧ Mean Sea Level, rounded to the nearest 0.1 meter.

ADDRESSES

City of Anderson
Maps are available for inspection at 401 South Main Street, Anderson, SC 29624.

City of Belton
Maps are available for inspection at 306 Anderson Street, Belton, SC 29627.

Town of Honea Path
Maps are available for inspection at 30 North Main Street, Honea Path, SC 29654.

Town of Pelzer
Maps are available for inspection at 103 Courtney Street, Pelzer, SC 29669.

Town of Pendleton
Maps are available for inspection at 301 Greenville Street, Pendleton, SC 29670.

Town of Starr
Maps are available for inspection at 7725 State Highway 81, Starr, SC 29684.

Town of Williamston
Maps are available for inspection at 12 West Main Street, Williamston, SC 29697.

Unincorporated Areas of Anderson County
Maps are available for inspection at 101 South Main Street, Anderson, SC 29622.

(Catalog of Federal Domestic Assistance No. 97.022, ''Flood Insurance.'')

Dated: July 29, 2011.

Sandra K. Knight,

Deputy Federal Insurance and Mitigation Administrator, Mitigation, Department of Homeland Security, Federal Emergency Management Agency.

[FR Doc. 2011–20394 Filed 8–10–11; 8:45 am]

BILLING CODE 9110–12–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket No. 11–100; RM–11632, DA 11–1225]

Television Broadcasting Services; Eau Claire, WI

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission has before it a petition for rulemaking filed by Gray Television Licensee, LLC (''Gray''), licensee of WEAU–TV, channel 13, Eau Claire, Wisconsin, requesting the substitution of channel 38 for channel 13 at Eau Claire. The tower holding WEAU–TV's main antenna collapsed on March 22, 2011, which Gray must rebuild and also replace the station's transmission equipment. In addition, viewers have reported difficulties receiving the station's digital signal on channel 13 since the end of the digital transition. Substituting channel 38 for channel 13 will allow Gray to leverage the significant and unplanned cost of rebuilding the station.

DATES: Effective August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Joyce L. Bernstein, *joyce.bernstein@fcc.gov,* Media Bureau, (202) 418–1600.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's *Report and Order,* MB Docket No. 11–100, adopted July 20, 2011, and released July 22, 2011. The full text of this document is available for public inspection and copying during normal business hours in the FCC's Reference Information Center at Portals II, CY–A257, 445 12th Street, SW., Washington, DC 20554. This document will also be available via ECFS (*http://fjallfoss.fcc.gov/ecfs/*). This document may be purchased from the Commission's duplicating contractor, Best Copy and Printing, Inc., 445 12th Street, SW., Room CY–B402, Washington, DC 20554, telephone 1–800–478–3160 or via the company's Web site, *http://www.bcipweb.com.* To request materials in accessible formats for people with disabilities (braille, large print, electronic files, audio format), send an e-mail to *fcc504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at 202–418–0530 (voice), 202–418–0432 (tty).

This document does not contain information collection requirements subject to the Paperwork Reduction Act of 1995, Public Law 104–13. In addition, therefore, it does not contain any information collection burden ''for small business concerns with fewer than 25 employees,'' pursuant to the Small Business Paperwork Relief Act of 2002, Public Law 107–198, *see* 44 U.S.C. 3506(c)(4). Provisions of the Regulatory Flexibility Act of 1980 do not apply to this proceeding.

The Commission will send a copy of this *Report and Order* in a report to be sent to Congress and the Government Accountability Office pursuant to the Congressional review Act, *see* 5 U.S.C. 801(a)(1)(A).

List of Subjects in 47 CFR Part 73

Television.

Federal Communications Commission.

Kevin R. Harding,

Associate Chief, Video Division, Media Bureau.

Final Rule

For the reasons discussed in the preamble, the Federal Communications Commission amends 47 CFR part 73 as follows:

PART 73—RADIO BROADCAST SERVICES

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 47 U.S.C. 154, 303, 334, 336, and 339.

§ 73.622 [Amended]

■ 2. Section 73.622(i), the Post-Transition Table of DTV Allotments under Wisconsin, is amended by adding channel 38 and removing channel 13 at Eau Claire.

[FR Doc. 2011–19839 Filed 8–10–11; 8:45 am]

BILLING CODE 6712–01–P

Proposed Rules

Federal Register
Vol. 76, No. 155
Thursday, August 11, 2011

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

SECURITIES AND EXCHANGE COMMISSION

17 CFR Part 230

[Release No. 33–9251; File No. S7–31–11]

RIN 3235–AL20

Covered Securities Pursuant to Section 18 of the Securities Act of 1933

AGENCY: Securities and Exchange Commission.

ACTION: Proposed rule.

SUMMARY: The Securities and Exchange Commission (''SEC'' or ''Commission'') proposes for comment an amendment to Rule 146 under Section 18 of the Securities Act of 1933 (''Securities Act''), as amended, to designate certain securities on BATS Exchange, Inc. (''BATS'' or ''Exchange'') as covered securities for purposes of Section 18 of the Securities Act. Covered securities under Section 18 of the Securities Act are exempt from state law registration requirements.

DATES: Comments should be received on or before September 12, 2011.

ADDRESSES: Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/proposed.shtml*); or

• Send an e-mail to *rule-comments@sec.gov.* Please include File Number S7–31–11 on the subject line.

• Use the Federal eRulemaking Portal (*http://www.regulations.gov*). Follow the instructions for submitting comments.

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number S7–31–11. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/proposed.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly.

FOR FURTHER INFORMATION CONTACT: David R. Dimitrious, Senior Special Counsel, (202) 551–5131, Ronesha Butler, Special Counsel, (202) 551–5629 or Carl Tugberk, Special Counsel, (202) 551–6049, Division of Trading and Markets (''Division''), Commission, 100 F Street, NE., Washington, DC 20549–6628.

SUPPLEMENTARY INFORMATION:

I. Introduction

In 1996, Congress amended Section 18 of the Securities Act to exempt from state registration requirements securities listed, or authorized for listing, on the New York Stock Exchange LLC (''NYSE''), the American Stock Exchange LLC (''Amex'') (now known as NYSE Amex LLC),[1] or the National Market System of The NASDAQ Stock Market LLC (''Nasdaq/NGM'') [2] (collectively, the ''Named Markets''), or any national securities exchange designated by the Commission to have substantially similar listing standards to those of the Named Markets.[3] More specifically, Section 18(a) of the Securities Act provides that ''no law, rule, regulation, or order, or other administrative action of any State * * * requiring, or with respect to, registration or qualification of securities * * * shall directly or indirectly apply to a security that—(A) is a covered security.'' [4] Covered securities are defined in Section 18(b)(1) of the Securities Act to include those securities listed, or authorized for listing, on the Named Markets, or securities listed, or authorized for listing, on a national securities exchange (or tier or segment thereof) that has listing standards that the Commission determines by rule are ''substantially similar'' to those of the Named Markets (''Covered Securities'').[5]

Pursuant to Section 18(b)(1)(B) of the Securities Act, the Commission adopted Rule 146.[6] Rule 146(b) lists those

[1] On October 1, 2008, NYSE Euronext acquired The Amex Membership Corporation (''AMC'') pursuant to an Agreement and Plan of Merger, dated January 17, 2008 (the ''Merger''). In connection with the Merger, NYSE Amex's predecessor, the Amex, a subsidiary of AMC, became a subsidiary of NYSE Euronext called NYSE Alternext US LLC (''NYSE Alternext''). *See* Securities Exchange Act Release No. 58673 (September 29, 2008), 73 FR 57707 (October 3, 2008) (SR–NYSE–2008–60 and SR–Amex–2008–62) (approving the Merger). In 2009, the Exchange changed its name from NYSE Alternext to NYSE Amex LLC (''NYSE Amex''). *See* Securities Exchange Act Release No. 59575 (March 13, 2009), 74 FR 11803 (March 19, 2009) (SR–NYSEALTR–2009–24) (approving the name change).

[2] As of July 1, 2006, the National Market System of The NASDAQ Stock Market LLC is known as the Nasdaq Global Market (''NGM''). *See* Securities Exchange Act Release Nos. 53799 (May 12, 2006), 71 FR 29195 (May 19, 2006) and 54071 (June 29, 2006), 71 FR 38922 (July 10, 2006).

[3] *See* National Securities Markets Improvement Act of 1996, Pub. L. 104–290, 110 Stat. 3416 (October 11, 1996).

[4] 15 U.S.C. 77r(a).

[5] 15 U.S.C. 77r(b)(1)(A) and (B). In addition, securities of the same issuer that are equal in seniority or senior to a security listed on a Named Market or national securities exchange designated by the Commission as having substantially similar listing standards to a Named Market are covered securities for purposes of Section 18 of the Securities Act. 15 U.S.C. 77r(b)(1)(C).

[6] Securities Exchange Act Release No. 39542 (January 13, 1998), 63 FR 3032 (January 21, 1998) (determining that the listing standards of the Chicago Board Options Exchange, Incorporated (''CBOE''), Tier 1 of the Pacific Exchange, Inc. (''PCX'') (now known as NYSE Arca, Inc.), and Tier 1 of the Philadelphia Stock Exchange, Inc. (''Phlx'') (now known as NASDAQ OMX PHLX LLC) were substantially similar to those of the Named Markets and that securities listed pursuant to those standards would be deemed Covered Securities for purposes of Section 18 of the Securities Act). In 2004, the Commission amended Rule 146(b) to designate options listed on the International Securities Exchange, Inc. (''ISE'') (now known as

national securities exchanges, or segments or tiers thereof, that the Commission has determined to have listing standards substantially similar to those of the Named Markets and thus securities listed on such exchanges are deemed Covered Securities.[7] BATS has filed a proposed rule change for the listing of securities on BATS[8] and has petitioned the Commission to amend Rule 146(b) to designate such securities as Covered Securities for the purpose of Section 18 of the Securities Act.[9] If the Commission were to approve the proposed listing standards and make this determination, then securities listed on BATS would be exempt from state law registration requirements.[10] Additionally, should the Commission approve BATS' proposed listing standards and the securities listed, or authorized for listing, on BATS were designated as Covered Securities under Rule 146(b)(1), then BATS' listing standards would be subject to Rule 146(b)(2) under the Securities Act. Rule 146(b)(2) conditions the designation of securities as Covered Securities under Rule 146(b)(1) on the identified exchange's listing standards continuing to be substantially similar to those of the Named Markets. Thus, under Rule 146(b)(2), the designation of certain securities as Covered Securities would be conditioned on BATS maintaining listing standards for its equity securities that are substantially similar to those of the Named Markets.

II. Background

In 1998, the CBOE, PCX (now known as NYSE Arca, Inc.), Phlx,[11] and the Chicago Stock Exchange, Inc. (''CHX'') petitioned the Commission to adopt a rule determining that specified portions of the exchanges' listing standards were substantially similar to the listing standards of the Named Markets.[12] In response to the petitions, and after extensive review of the petitioners' listing standards, the Commission adopted Rule 146(b), determining that the listing standards of the CBOE, Tier 1 of the PCX, and Tier 1 of the Phlx were substantially similar to those of the Named Markets and that securities listed pursuant to those standards would be deemed Covered Securities.[13] In 2004, ISE petitioned the Commission to amend Rule 146(b) to determine that its listing standards for securities listed on ISE are substantially similar to those of the Named Markets and, accordingly, that securities listed pursuant to such listing standards are Covered Securities for purposes of Section 18(b) of the Securities Act.[14] The Commission subsequently amended Rule 146(b) to designate options listed on ISE as Covered Securities.[15] In 2007, Nasdaq petitioned the Commission to amend Rule 146(b) to determine that listing standards for securities listed on the NCM are substantially similar to those of the Named Markets and, accordingly, that securities listed pursuant to such listing standards are Covered Securities.[16] The Commission subsequently amended Rule 146(b) to designate securities listed on the NCM as Covered Securities.[17]

BATS has petitioned the Commission to amend Rule 146(b) and determine that its proposed listing standards for securities listed on BATS are substantially similar to those of the Named Markets, and that such securities are Covered Securities under Section 18(b) of the Securities Act.[18]

III. Discussion

Under Section 18(b)(1)(B) of the Securities Act,[19] the Commission has the authority to determine that the listing standards of an exchange, or tier or segment thereof, are substantially similar with those of the NYSE, NYSE Amex, or Nasdaq/NGM. The Commission initially has compared BATS' proposed listing standards for all securities with one of the Named Markets. If the proposed listing standards in a particular category were not substantially similar to the standards of that market, the Commission compared BATS' proposed standards to one of the other two markets.[20] In addition, as it has done previously, the Commission has interpreted the ''substantially similar'' standard to require listing standards at least as comprehensive as those of the Named Markets.[21] If a petitioner's listing standards are higher than the Named Markets, then the Commission may still determine that the petitioner's listing standards are substantially similar to those of the Named Markets.[22] Finally, the Commission notes that differences in language or approach would not necessarily lead to a determination that the listing standards of the petitioner are not substantially similar to those of any Named Market.[23]

The Commission has reviewed proposed listing standards for securities to be listed and traded on BATS and, for the reasons discussed below, preliminarily believes that the proposed standards overall are substantially similar to those of a Named Market.[24]

A. Qualitative Listing Standards

BATS' proposed qualitative listing standards for both the Tier I and Tier II securities are substantively identical to

the International Securities Exchange, LLC) as Covered Securities for purposes of Section 18(b) of the Securities Act. *See* Securities Act Release No. 8442 (July 14, 2004), 69 FR 43295 (July 20, 2004). In 2007, the Commission amended Rule 146(b) to designate securities listed on the Nasdaq Capital Market (''NCM'') as Covered Securities for purposes of Section 18(b) of the Securities Act. *See* Securities Act Release No. 8791 (April 18, 2007), 72 FR 20410 (April 24, 2007).

[7] 17 CFR 230.146(b).

[8] *See* Securities Exchange Act Release No. 64546 (May 25, 2011), 76 FR 31660 (June 1, 2011) (proposing qualitative and quantitative listing requirements and standards for securities).

[9] *See* letter from Eric Swanson, Senior Vice President and General Counsel, BATS, to Elizabeth M. Murphy, Secretary, Commission, dated May 26, 2011 (File No. 4–632) (''BATS Petition'').

[10] 15 U.S.C. 77r.

[11] On July 24, 2008, The NASDAQ OMX Group, Inc. acquired Phlx and renamed it ''NASDAQ OMX PHLX LLC.'' *See* Securities Exchange Act Release Nos. 58179 (July 17, 2008), 73 FR 42874 (July 23, 2008) (SR–Phlx–2008–31); and 58183 (July 17, 2008), 73 FR 42850 (July 23, 2008) (SR–NASDAQ–2008–035). *See also* Securities Exchange Act Release No. 62783 (August 27, 2010), 75 FR 54204 (September 3, 2010) (SR–Phlx–2010–104).

[12] *See* letter from David P. Semak, Vice President, Regulation, PCX, to Arthur Levitt, Jr., Chairman, Commission, dated November 15, 1996; letter from Alger B. Chapman, Chairman, CBOE, to Jonathan G. Katz, Secretary, Commission, dated November 18, 1996; letter from J. Craig Long, Esq., Foley & Lardner, Counsel to CHX, to Jonathan G. Katz, Secretary, Commission, dated February 4, 1997; and letter from Michele R. Weisbaum, Vice President and Associate General Counsel, Phlx, to Jonathan G. Katz, Secretary, Commission, dated March 31, 1997.

[13] Securities Exchange Act Release No. 39542, *supra* note 6. The Commission did not include Tier 1 of the CHX in Rule 146 because of ''concerns regarding the CHX's listing and maintenance procedures.'' *Id.* at 3032.

[14] *See* letter from Michael Simon, Senior Vice President and General Counsel, ISE, to Jonathan G. Katz, Secretary, Commission, dated October 9, 2003.

[15] Securities Act Release No. 8442 (July 14, 2004), 69 FR 43295 (July 20, 2004).

[16] *See* letter from Edward S. Knight, Executive Vice President and General Counsel, Nasdaq, to Nancy M. Morris, Secretary, Commission, dated March 1, 2006 (File No. 4–513).

[17] *See* Securities Act Release No. 8791, *supra* note 6.

[18] *See* BATS Petition, *supra* note 9.

[19] 15 U.S.C. 77r(b)(1)(B).

[20] This approach is consistent with the approach that the Commission has previously taken. *See* Securities Act Release No. 7494 (January 13, 1998), 63 FR 3032 (January 21, 1998).

[21] *See id.*

[22] *See* Securities Act Release No. 8791, *supra* note 6.

[23] *Id.*

[24] *See generally* proposed BATS Chapter XIV; Securities Exchange Act Release No. 64546, *supra* note 8, 76 FR 31660. In making its preliminary determination of substantial similarity, as discussed in detail below, the Commission generally compared BATS' proposed qualitative listing standards for both Tier I and Tier II securities with Nasdaq/NGM's qualitative listing standards, BATS' proposed quantitative listing standards for Tier I securities with Nasdaq/NGM's quantitative listing standards, and BATS' proposed quantitative listing standards for Tier II securities with NYSE Amex's quantitative listing standards.

the qualitative listing standards for Nasdaq/NGM securities.[25] Therefore, the Commission preliminarily believes that BATS' qualitative listing standards for Tier I and Tier II securities are substantially similar to a Named Market.

The Commission requests comment on whether BATS' proposed qualitative listing standards for Tier I and Tier II are ''substantially similar'' to Nasdaq/NGM's listing standards.

B. Tier I Securities Quantitative Listing Standards

The Commission believes that BATS' proposed initial and continued listing standards for its Tier I Securities are substantively identical to the initial and continued listing standards for securities listed on Nasdaq/NGM.[26] Therefore, the Commission preliminarily believes that BATS' quantitative listing standards for Tier I Securities are substantially similar to a Named Market.

The Commission requests comment on whether BATS' proposed Tier I Securities quantitative listing rules are ''substantially similar'' to Nasdaq/NGM's listing rules.

C. Tier II Securities Quantitative Listing Standards

1. Primary Equity Securities

The Commission compared BATS' proposed listing standards for primary equity securities listed on Tier II of the Exchange to the listing standards of NYSE Amex.[27] The Commission preliminarily believes that BATS' proposed initial listing standards for primary equity securities listed on Tier II of the Exchange are substantially similar to those of NYSE Amex's common stock listing standards.[28] Specifically, BATS' proposed requirements relating to bid price,[29] round lot holders,[30] shares held by the public,[31] and required number of registered and active market makers[32] are substantially similar to NYSE Amex requirements. Additionally, BATS' proposed equity,[33] market value,[34] and net income[35] standards are also substantially similar to NYSE Amex standards.

In addition to the above initial listing requirements, BATS would require that American Depositary Receipts (''ADRs'') comply with an additional criterion. Specifically, BATS would require there be at least 400,000 ADRs issued for such securities to be initially listed on BATS.[36] However, NYSE Amex does not have specific requirements for ADRs in addition to its initial listing standards for primary equity securities.[37] As noted above, the Commission may still determine that the petitioner's listing standards are similar to those of the Named Markets if BATS' proposed listing standards are higher than the Named Markets.[38] The Commission preliminarily believes that BATS' proposed listing requirements for ADRs are substantially similar to those of NYSE Amex.

The Commission also preliminarily believes that the proposed continued listing requirements for primary equity securities listed on Tier II of the Exchange, while not identical, are substantially similar to those of NYSE Amex.[39] NYSE Amex's delisting criteria are triggered by poor financial conditions or operating results of the

[25] Such qualitative listing standards relate to, among other things, the number of independent directors required, conflicts of interest, composition of the audit committee, executive compensation, shareholder meeting requirements, voting rights, quorum, code of conduct, proxies, shareholder approval of certain corporate actions, and the annual and interim reports requirements. *Compare* proposed BATS Rules 14.6 and 14.10 *with* Nasdaq Rule 5250 and Rule 5600 Series.

[26] *Compare* proposed BATS Rules 14.4(a) and 14.8 *with* Nasdaq Rule 5225(a) and Nasdaq Rule 5400 Series (providing for identical rules concerning initial listing and maintenance standards for units, primary equity securities, preferred stock and secondary classes of common stock, rights, warrants and convertible debt on BATS and the Nasdaq/NGM).

[27] *See generally* Sections 101 and 102 of the NYSE Amex Company Guide and proposed BATS Rule 14.9.

[28] BATS' proposed use of ''primary equity securities'' and NYSE Amex's use of ''common stock'' is simply a difference in nomenclature, as BATS' proposed listing standards define ''primary equity security'' as a company's first class of common stock. *See* proposed BATS Rule 14.1(a)(21).

[29] BATS' proposed listing standards would require a minimum bid price of $4 per share for initial listing and $1 per share for continued listing while NYSE Amex requires a minimum bid price of $2–$3 per share depending on the issuer for initial listing and will consider delisting if the price per share is ''low.'' *Compare* proposed BATS Rule 14.9(b)(1)(A) *with* Section 102 of the NYSE Amex Company Guide. The Commission has interpreted the substantially similar standard to require listing standards at least as comprehensive as those of the Named Markets; the Commission may determine that a petitioner's standards are substantially similar if they are higher, and differences in language or approach of the listing standards are not dispositive. *See supra* notes 21–23 and accompanying text.

[30] While BATS' proposed listing standards would require at least 300 round lot holders, NYSE Amex's listing standards require 400 or 800 public shareholders (depending upon the number of shares held by the public), or 300 or 600 public shareholders for its alternate listing standards. The Commission preliminarily does not believe this difference would preclude a determination of substantial similarity between the standards. Additionally, BATS' proposed listing standards are identical to the listing standards of NCM, which the Commission previously found to be substantially similar to a Named Market. *See* Securities Act Release 8791, *supra* note 6 (determining that NCM listing standards, which are identical to BATS' proposed listing standards for primary equity securities on Tier II of the Exchange, are substantially similar to these same Amex standards). With respect to NCM having alternative listing standards for the number of round lot holders, the Commission noted that this difference did not preclude a determination of substantial similarity between the standards. *See* Securities Act Release 8791, *supra* note 6, 72 FR at 20412; Securities Act Release No. 8754 (November 22, 2006), 71 FR 67762 (November 22, 2006) (proposing that the Commission amend Rule 146(b) to designate securities listed on the NCM as covered securities for purposes of Section 18(b) of the Securities Act).

[31] BATS' proposed listing standards would require a minimum of 1,000,000 publicly held shares while NYSE Amex requires a minimum of 500,000. *Compare* proposed BATS Rule 14.9(b)(1)(B) *with* Section 102(a) of the NYSE Amex Company Guide. The Commission has interpreted the substantially similar standard to require listing standards at least as comprehensive as those of the Named Markets; the Commission may determine that a petitioner's standards are substantially similar if they are higher, and differences in language or approach of the listing standards are not dispositive. *See supra* notes 21–23 and accompanying text.

[32] BATS' proposed listing requirements would require at least three registered and active market makers while NYSE Amex requires one specialist to be assigned. *Compare* proposed BATS Rule 14.9(b)(1)(D) *with* Section 202(e) of the NYSE Amex Company Guide. The Commission may still determine that the petitioner's listing standards are substantially similar to those of the Named Markets if a petitioner's listing standards are higher than the Named Markets. *See* Securities Act Release No. 8791, *supra* note 6.

[33] BATS' proposed listing standard would require a company to have stockholder equity of at least $5 million, a market value of publicly held shares of at least $15 million, and a two-year operating history. *See* proposed BATS Rule 14.9(b)(2)(A). NYSE Amex requires stockholder equity of at least $4 million, a market value of publicly held shares of at least $15 million, and a two-year operating history.

[34] BATS' proposed listing standards would require a market value of listed securities of at least $50 million and a market value of publicly held shares of at least $15 million, which is the same as required by NYSE Amex. *Compare* proposed BATS Rule 14.9(b)(2)(B) *with* Section 101(c)(2)–(3) of the NYSE Amex Company Guide.

[35] BATS' proposed listing standards would require net income from continuing operations of at least $750,000, which is the same as required by NYSE Amex. *Compare* proposed BATS Rule 14.9(b)(2)(C) *with* Section 101(d)(1) of the NYSE Amex Company Guide.

[36] *See* proposed BATS Rule 14.9(b)(1)(E). This proposed requirement is identical to NCM. *See* Nasdaq Rule 5505(a)(5); *see generally* Securities Act Release 8791, *supra* note 6 (determining that NCM listing standards, which are identical to BATS' proposed standards for primary equity securities on Tier II of the Exchange, are substantially similar to the Amex standards).

[37] *See* Section 102 of the NYSE Amex Company Guide. *See also* Section 110 of the NYSE Amex Company Guide.

[38] *See* Securities Act Release No. 8791, *supra* note 6.

[39] *See generally* Securities Act Release 8791, *supra* note 6 (determining that NCM continued listing standards, which are identical to BATS' proposed continued listing standards for primary equity securities on Tier II of the Exchange, are substantially similar to the Amex standards).

issuer.[40] Specifically, NYSE Amex will consider delisting an equity issue if: (i) Stockholders' equity is less than $2 million and such issuer has sustained losses from continuing operations and/or net losses in two of its three most recent fiscal years; (ii) stockholders' equity is less than $4 million and such issuer has sustained losses from continuing operations and/or net losses in three of its four most recent fiscal years; (iii) stockholders' equity is less than $6 million if such issuer has sustained losses from continuing operations and/or net losses in its five most recent fiscal years; or (iv) the issuer has sustained losses which are so substantial in relation to its overall operations or its existing financial resources, or its financial condition has become so impaired that it appears questionable, in the opinion of the exchange, as to whether such company will be able to continue operations and/or meet its obligations as they mature.[41]

Although BATS would not have the same continued listing provisions for Tier II, BATS also would look at the financial condition and operating results of the issuer in order to determine whether to delist an issuer. BATS' continued listing standards for Tier II securities would require compliance with either a (1) Shareholder equity, (2) market value of listed securities or (3) net income standard. Specifically, for continued listing, BATS would require shareholder's equity of at least $2.5 million, market value of listed securities of at least $35 million, or net income of $500,000 from continuing operations in the past fiscal year or two out of three past fiscal years.[42] Further, BATS would require an issuer to have (i) A minimum bid price for continued listing of $1 per share,[43] (ii) at least two registered and active market makers, (iii) 300 public holders, and (iv) a minimum number of publicly held shares of at least 500,000 shares with a market value of at least $1 million.[44] The Commission preliminarily believes that the differences in the maintenance criteria for common stock listed on NYSE Amex and as proposed on BATS for Tier II Securities are not significant and that, taken as a whole, the criteria are substantially similar.[45]

The Commission requests comment on whether BATS' proposed listing standards for primary equity securities on Tier II are ''substantially similar'' to NYSE Amex standards.

2. Preferred Stock and Secondary Classes of Common Stock

The Commission has compared the proposed listing standards of preferred stock and secondary classes of common stock on Tier II of the Exchange to the Nasdaq/NGM standards and preliminarily believes that BATS' standards are substantially similar to those of Nasdaq/NGM. A secondary class of common stock is a class of common stock of an issuer that has another class of common stock listed on an exchange.[46] The Commission preliminarily believes that BATS' proposed initial and continued listing standards with respect to the number of round lot holders,[47] bid price,[48] number of publicly held shares,[49] market value of publicly held shares,[50] and number of market makers [51] are substantially similar to the Nasdaq/NGM standards.[52]

The Commission requests comment on whether the BATS proposed

[40] *See generally* Sections 1001 through 1006 of the NYSE Amex Company Guide.

[41] *See* Section 1003(a) of the NYSE Amex Company Guide. While not identical to NYSE Amex, BATS, as noted below, also has a shareholder equity standard. *See infra* note 42 and accompanying text. NYSE Amex, however, will not normally consider suspending dealing in (i) through (iii) noted above if the issuer is in compliance with the following: (1) Total market value of market capitalization of at least $50,000,000; or total assets and revenue of $50,000,000 each in its last fiscal year, or in two of its last three fiscal years; and (2) the issuer has at least 1,100,000 shares publicly held, a value of publicly held shares of at least $15,000,000 and 400 round lot holders. *Id.*

NYSE Amex also will consider delisting if: (i) An issuer has sold or otherwise disposed of its principal operating assets or has ceased to be an operating company or has discontinued a substantial portion of its operations or business; (ii) if substantial liquidation of the issuer has been made; or (iii) if advice has been received, deemed by the Exchange to be authoritative, that the security is without value, or in the case of a common stock, such stock has been selling for a substantial period of time at a low price. *See* Section 1003(c) and (f)(v) of the NYSE Amex Company Guide.

[42] Proposed BATS Rule 14.9(e)(2)(A)–(C). NYSE Amex focuses on a shareholder equity standard for continued listing. BATS' proposed shareholder equity standard would require at least $2.5 million shareholders' equity compared to NYSE Amex's lowest shareholder equity standard of $2 million, if the NYSE Amex issuer has sustained losses from continuing operations and/or net losses in two of its three most recent fiscal years. *Compare* proposed BATS Rule 14.9(e)(2)(A)–(C) *with* Section 1003(a) of the NYSE Amex Company Guide.

[43] *See* proposed BATS Rule 14.9(e)(1)(B). Amex will consider delisting if the price per share is ''low.'' *See* Section 1003(f)(v) of the Amex Company Guide. *See also* Securities Act Release 8791, *supra* note 6 (noting the same regarding the NCM and Amex bid price standards).

[44] Proposed BATS Rule 14.9(e)(1)(A)–(E). NYSE Amex will consider delisting the common stock of an issuer if the aggregate market value of such publicly held shares is less than $1 million for more than 90 consecutive days, the number of publicly held shares is less than 200,000 shares, or the number of its public stockholders is less than 300. *See* Section 1003(b) of the NYSE Amex Company Guide.

[45] The Commission has interpreted the substantially similar standard to require listing standards at least as comprehensive as those of the Named Markets, and differences in language or approach of the listing standards are not dispositive. *See supra* notes 21–23 and accompanying text. *See also* Securities Act Release 8791, *supra* note 6 (determining that NCM continued listing standards, which are identical to BATS' proposed continued listing standards for primary equity securities on Tier II of the Exchange, are substantially similar to the Amex standards).

[46] *See* Securities Act Release No. 8791, *supra* note 6, at 20411.

[47] BATS' proposed initial listing standard would require 100 round lot holders, as Nasdaq/NGM requires. *Compare* proposed BATS Rule 14.9(c) *with* Nasdaq Rule 5510. Similarly, BATS' proposed continued listing standard would require 100 round lot holders. The Nasdaq/NGM continued listing standard requires 100 round lot holders. *Compare* proposed BATS Rule 14.9(f) *with* Nasdaq Rule 5460(a)(4).

[48] While BATS' proposed bid price requirement for initial listing is $4 and the Nasdaq/NGM requirement is $5, the Commission preliminarily does not believe this difference is significant. *Compare* proposed BATS Rule 14.9(c)(1)(A) *with* Nasdaq Rule 5510(a)(1). *See also* Securities Act Release No. 8791, *supra* note 6, at 20412 n. 28 (determining that an NCM bid requirement, which is identical to BATS' proposed bid requirement, was substantially similar to the Nasdaq/NGM requirement). Both BATS' proposed standard and Nasdaq/NGM's existing standard require a $1 bid price for continued listing. *Compare* proposed BATS Rule 14.9(f)(1) *with* Nasdaq Rule 5460(a)(3).

[49] BATS' proposed standard would require 200,000 publicly held shares for initial listing, and 100,000 publicly held shares for continued listing, which is the same as Nasdaq/NGM requires. *Compare* proposed BATS Rule 14.9(c)(1)(C) and 14.9(f)(1)(c) *with* Nasdaq Rules 5415(a)(1) and 5460(a)(1).

[50] BATS' proposed standard for initial listing of preferred stock or a secondary class of common stock would require a market value of publicly held shares of at least $3.5 million. Nasdaq/NGM requires a market value of publicly held shares of at least $4 million. *Compare* proposed BATS Rule 14.9(c)(1)(D) *with* Nasdaq Rule 5415(a)(2). BATS proposed standard for continued listing would require a market value of publicly held shares of at least $1 million. Nasdaq/NGM requires a market value of publicly held shares of at least $1 million for continued listing. *Compare* proposed BATS Rule 14.9(f)(1)(D) *with* Nasdaq Rule 5460(a)(1). The Commission preliminarily believes BATS' proposed initial and continued listing standards for preferred stock and secondary classes of common stock are substantially similar to Nasdaq/NGM. *See also* Securities Act Release No. 8791, *supra* note 6, at 20411–12. (determining that NCM listing standards, which are identical to BATS' proposed listing standards for preferred stock and secondary classes of common stock, are substantially similar to the Nasdaq/NGM standards).

[51] BATS proposed standard for initial listing would require at least three registered and active market makers, while its continued listing standard would require at least two registered and active market makers. Nasdaq/NGM requires the same. *Compare* proposed BATS Rule 14.9(c)(1)(E) *with* Nasdaq Rule 5415(a)(2).

[52] The Commission notes that these proposed requirements would apply to instances when the common stock or common stock equivalent security of the issuer were listed on BATS as a Tier II Security or otherwise were a Covered Security. If the common stock or common stock equivalent is not listed as a Tier II Security or is a Covered Security, then the security would be required to meet the initial primary equity listing requirements for Tier II noted above. Nasdaq/NGM contains a similar requirement. *Compare* proposed BATS Rule 14.9(f)(2) *with* Nasdaq Rule 5460(b).

secondary classes of common stock and preferred stock rules are ''substantially similar'' to Nasdaq/NGM's rules.

3. Warrants

The Commission has compared BATS' proposed standards for warrants to Nasdaq/NGM's standards, and preliminarily believes that the BATS proposed standards are substantially similar to the Nasdaq/NGM standards. BATS' proposed initial listing standards would require that 400,000 warrants be outstanding for initial listing, and that there be at least three registered and active market makers and 400 round lot holders.[53] Nasdaq/NGM's standards are identical except that Nasdaq/NGM requires 450,000 warrants to be outstanding.[54] Though not identical with respect to the number of warrants outstanding standard, the Commission preliminarily believes these proposed initial listing standards are substantially similar to the Nasdaq/NGM standards.[55] Further, the proposed BATS standards would require the issuer's underlying security to be listed on the Exchange or be a Covered Security.[56] The Commission notes that Nasdaq/NGM has a similar standard that the underlying security be listed on Nasdaq/NGM or be a Covered Security and preliminarily believes that BATS' proposed standard is substantially similar to Nasdaq/NGM.[57]

The Commission also preliminarily believes that BATS' proposed continuing listing requirements for warrants that there be two registered and active market makers (one of which may be a market maker entering a stabilizing bid) and that the underlying security remain listed on the Exchange or be a Covered Security are substantially similar to that of Nasdaq/NGM.[58]

The Commission requests comment on whether BATS' proposed listing standards for warrants are ''substantially similar'' to Nasdaq/NGM's listing standards.

4. Index Warrants

For index warrants traded on BATS, BATS has proposed the same standards (both initial and continuing) that apply to index warrants traded on Nasdaq/NGM.[59] Therefore, the Commission preliminarily believes that the proposed listing standards for index warrants traded on BATS are substantially similar to the standards applicable to index warrants traded on the Nasdaq/NGM market.

The Commission requests comment on whether BATS proposed listing standards for index warrants are ''substantially similar'' to Nasdaq/NGM's listing standards.

5. Convertible Debt

The Commission has compared BATS' proposed listing standards for convertible debt to NYSE Amex's listing standards for debt. The Commission preliminarily believes that BATS' proposed initial listing standards regarding the threshold principal amount outstanding,[60] the availability of current last sale information,[61] and number of market makers [62] are substantially similar to NYSE Amex standards.[63] In addition to the requirements noted above, BATS' proposed listing standards would require that one of four additional conditions be met for listing of convertible debt. Specifically, BATS proposes that it would not list a convertible debt security unless one of the following conditions were met: (i) The issuer of the debt security also has equity securities listed on the Exchange, NYSE Amex, the NYSE, or Nasdaq/NGM; (ii) an issuer of equity securities listed on the Exchange, NYSE Amex, the NYSE, or Nasdaq/NGM directly or indirectly owns a majority interest in, or is under common control with, the issuer of the debt security, or has guaranteed the debt security; (iii) a nationally recognized securities rating organization (an ''NRSRO'') has assigned a current rating to the debt security that is no lower than an S&P Corporation ''B'' rating or equivalent rating by another NRSRO; or (iv) if no NRSRO has assigned a rating to the issue, an NRSRO has currently assigned an investment grade rating to an immediately senior issue or a rating that is no lower than an S&P Corporation ''B'' rating, or an equivalent rating by another NRSRO, to a pari passu or junior issue.[64] The Commission preliminarily believes that these other conditions proposed by BATS for listing of convertible debt are substantially similar to NYSE Amex standards.[65]

The Commission requests comment on whether the BATS proposed convertible debt listing rules are ''substantially similar'' to NYSE Amex's listing standards for debt securities.

6. Units

The listing requirements for units on Tier II of the Exchange, NYSE Amex, and Nasdaq/NGM are all the same, as each evaluates the initial and continued listing of a unit by looking to its components.[66] If all of the components

[53] *See* proposed BATS Rule 14.9(d)(1)(A), (C) and (D).

[54] *See* Nasdaq Rule 5410(a), (c) and (d).

[55] *See also* Securities Act Release 8791, *supra* note 6 (determining that NCM initial listing standards, which are identical to BATS' proposed standards for warrants on Tier II of the Exchange, are substantially similar to the Amex standards).

[56] *See* BATS proposed Rule 14.9(d)(1)(B).

[57] *See* Nasdaq Rule 5410(b).

[58] *Compare* proposed BATS' Rule 14.9(g)(1) *with* Nasdaq Rule 5455(1) and (2).

[59] *Compare* proposed BATS' Rule 14.9(d)(3) *with* Nasdaq Rule 5725.

[60] The BATS proposed rule would require a principal amount outstanding of at least $10 million for initial listing and $5 million for continued listing. *See* proposed BATS Rule 14.9(d)(2)(A) and 14.9(g)(2)(A). NYSE Amex requires a principal amount outstanding of at least $5 million for initial listing and will consider delisting if the principal amount outstanding is less than $400,000 or if the issuer is not able to meet its obligations on the listed debt security. *See* Sections 104 and 1003 of the NYSE Amex Company Guide. As the Commission noted in a prior release, while these requirements are not identical, the Commission believes that both standards are designed to ensure the continued liquidity of the debt security, and thus are substantially similar. *See* Securities Act Release 8791, *supra* note 6, at 20412 (finding that an identical NCM listing standard was substantially similar to the Amex standard).

[61] Both BATS' proposed standard and NYSE Amex include an initial listing requirement that there be current last sale information available in the United States with respect to the underlying security into which the bond or debenture is convertible. *Compare* proposed BATS Rule 14.9(d)(2)(B) *with* Section 104 of the NYSE Amex Company Guide. Additionally, Section 1003(e) of the NYSE Amex Company Guide states that convertible bonds will be reviewed when the underlying security is delisted and will be delisted when the underlying security is no longer the subject of real-time reporting in the United States. BATS' continued listing standards for a convertible debt security also require that current last sale information be available in the United States with respect to the underlying security, whereas NYSE Amex does not. *Compare* proposed BATS Rule 14.9(g)(2)(C) *with* Section 1003(e) of the NYSE Amex Company Guide.

[62] BATS' proposed standard would require at least three registered and active market makers for initial listing and two registered and active market makers for continued listing (one of which may be a market maker entering a stabilizing bid), whereas NYSE Amex requires one specialist to be assigned. *Compare* proposed BATS Rule 14.9(d)(1)(C) *with* NYSE Amex Rule 104.

[63] NYSE Amex will not list a convertible debt issue containing a provision which gives an issuer discretion to reduce the conversion price unless the issuer establishes a minimum 10-day period within which such price reduction will be in effect. *See* Section 104 of the NYSE Amex Company Guide. The Commission preliminarily believes that omission of such a provision does not impact its determination. *See* Securities Act Release Nos. 39542, *supra* note 6 (finding PCX listing standards to be substantially similar to Amex even with the absence of this provision); 8791, *supra* note 6, at 20412 (finding NCM's listing standard, which is identical to BATS' proposed listing standard for convertible debt, is substantially similar to Amex even with the absence of this provision).

[64] These standards are identical to the initial listing standard for convertible debt securities on NYSE Amex and NCM). *Compare* proposed BATS Rule 14.9(d)(2)(D)(iv) *with* Section 104(A)–(E) of the NYSE Amex Company Guide *and* Nasdaq Rule 5515(b)(4).

[65] *Id.*

[66] A unit is a type of security consisting of two or more different types of securities (e.g., a

of a unit individually meet the standards for listing, then the unit would meet the standards for listing.[67] Because the components for units proposed by BATS are substantially similar to those of a Named Market, as discussed above, the Commission preliminarily believes that BATS' proposed listing standards for units to be listed on Tier II of the Exchange are substantially similar to a Named Market.[68]

The Commission requests comment on whether BATS' proposed listing standards for units on Tier II of the Exchange are ''substantially similar'' to NYSE Amex requirements.

D. Other Securities Including Exchange Traded Funds, Portfolio Depository Receipts and Index Fund Shares

In addition to the proposed listing standards for Tier I and Tier II securities and the analyses of such standards to the Named Markets discussed above, the Commission notes that BATS has proposed listing standards for other securities, including exchange traded funds, portfolio depository receipts, and index fund shares. The Commission also notes that BATS' proposed standards for these securities are identical to those of Nasdaq/NGM.[69]

E. Other Changes

Sections (b)(1) and (b)(2) of Rule 146 use the term ''Amex'' to refer to the American Stock Exchange LLC. As noted above, on October 1, 2008, NYSE Euronext acquired Amex and renamed it NYSE Alternext.[70] Further, in 2009, NYSE Alternext was renamed NYSE Amex LLC.[71] Additionally, Section (b)(1) of Rule 146 uses the term ''the Philadelphia Stock Exchange, Inc.'' As noted above, on July 24, 2008, The NASDAQ OMX Group, Inc. acquired Phlx and renamed it ''NASDAQ OMX PHLX LLC.''[72] The proposed rule change includes changes to Rule 146(b) to account for these name changes.

F. Comments

To date, the Commission has not received any comment letters on the Petition.

IV. Solicitation of Comments

The Commission seeks comment generally on the desirability of amending Rule 146(b) to include securities listed, or authorized for listing, of BATS. As discussed above, based on its review of BATS' proposed listing standards, the Commission preliminarily believes that the proposed initial and continued listing standards for BATS are substantially similar to those of the NYSE Amex or Nasdaq/NGM. The Commission seeks comments on its preliminary analysis.

The Commission also invites commenters to provide views and data as to the costs, benefits, and effects associated with the proposed amendments. In addition to the questions posed above, commenters are welcome to offer their views on any other matter raised by the proposed amendment to Rule 146(b), including the application of rule 146(b)(2). Finally, the Commission requests comment on whether it could use a different methodology to determine whether BATS' proposed listing standards are ''substantially similar'' to those of the Named Markets.

V. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 does not apply because the proposed amendment to Rule 146(b) does not impose recordkeeping or information collection requirements or other collection of information, which require the approval of the Office of Management and Budget under 44 U.S.C. 3501 *et seq.*

VI. Economic Analysis

A. Introduction

Section 2(b) of the Securities Act[73] requires us, when engaging in rulemaking where we are required to consider or determine whether an action is necessary or appropriate in the public interest, to consider, in addition to the protection of investors, whether the action will promote efficiency, competition and capital formation. We have considered, and discuss below, the effects of the proposed amendment to Securities Act Rule 146, with regard to BATS' proposed listing standards to designate certain securities that would be listed on BATS as Covered Securities, on efficiency, competition, and capital formation, as well as the benefits and costs associated with the proposed rulemaking.

Congress amended Section 18 of the Securities Act to exempt covered securities from state registration requirements. These securities are listed on the Named Markets or any other national securities exchange determined by the Commission to have ''substantially similar'' listing standards to those of the Named Markets (''Designated Markets'').[74] The Commission proposes to determine (if the Commission were to approve the proposed listing standards filed by BATS) that the listing standards for securities listed on BATS are substantially similar to those of a Named Market, specifically Nasdaq/NGM or NYSE Amex. Securities listed, or authorized for listing, on BATS therefore would be exempt from state law registration requirements.

There are three Named Markets (NYSE, NYSE Amex, and Nasdaq/NGM) and currently five Designated Markets (Tier I of NYSE Arca, Tier I of the Philadelphia Stock Exchange, CBOE, ISE, and Nasdaq/NCM). NYSE and Nasdaq/NGM are currently the largest exchanges in terms of number of securities listed. As of April 19, 2011, in terms of securities listed, NYSE lists 3,255, Nasdaq/NGM lists 2,854, NYSE Arca lists 1,213, and NYSE Amex lists 544.[75]

The direct economic effect of the proposed rule would be to exempt issuers that list, or are authorized to list, on BATS from the requirements of state registration. Instead, these issuers would be required to comply with BATS' proposed listing standards and the federal securities laws, rules and regulations with respect to the registration and sale of securities. The requirements of state registration typically include: (i) Paperwork and labor hours necessary to comply with state registration requirements, (ii) meeting the disclosure standards, and (iii) in some states, meeting certain minimum merit requirements to make public offerings.[76]

combination of common stocks and warrants). *See, e.g.,* Securities Exchange Act Release No. 48464 (September 9, 2003), 68 FR 54250 (September 16, 2003) (order approving NYSE Amex proposed rule change to amend Sections 101 and 1003 of the NYSE Amex Company Guide to clarify the listing requirements applicable to units).

[67] *See generally* proposed BATS Rule 14.4, Section 101(f) of the NYSE Amex Company Guide, and Nasdaq Rule 5225.

[68] *See* Securities Exchange Act Release No. 64546, *supra* note 8, 76 FR 31660 at 31664.

[69] *Compare* proposed BATS Rule 14.11 *with* Nasdaq Rule 5700 Series.

[70] *See* Securities Exchange Act Release No. 58673, *supra* note 1.

[71] *See* Securities Exchange Act Release No. 59575, *supra* note 1.

[72] *See* Securities Exchange Act Release Nos. 58179, 58183, and 62783, *supra* note 11.

[73] 15 U.S.C. 77b(b).

[74] *See* 15 U.S.C. 77r(b)(1)(B).

[75] These listed securities include exchange traded funds and multiple securities from the same issuer.

[76] A commentator noted that the purpose of such review is ''to prevent 'unfair' and 'oppressive' offerings of securities,'' and, as of 2011, merit review is employed in about 30 states. *See* Jeffrey B. Bartell & A.A. Sommer, Jr., *Blue Sky Registration, in* Securities Law Techniques (Matthew Bender ed., 2011). Typical elements of merit review include: offering expenses, including underwriter's compensation, rights of security holders, historical ability to service debt or pay dividends, financial

Continued

An indirect effect of the proposed rule would be that, by removing the requirements of state registration for issuers that list, or are authorized to list, on BATS—the same privilege granted to other Covered Securities—the rule could improve BATS' ability to compete effectively with other exchanges. Therefore, an important economic effect of the rule could be to engender greater competition in the market for listing services.

Exchanges generally compete in multiple areas, which include the market for listing, the market for trading, and the market for order-flow. This proposed rule and BATS' proposed listing standards [77] relate primarily to the market for listing, although the proposed rule (should it be adopted) and the entry of a new participant in the listings market could impact other markets as well.[78] In the market for listing, exchanges compete for issuers to list on their exchanges, so that the exchange may collect listing fees. Domestic exchanges face listing competition from other domestic exchanges and from foreign exchanges.[79] The benefit of listing for issuers generally is to gain greater access to capital through measures designed to help promote quality certification and visibility to public investors, which will generally result in a reduction in the cost of raising capital for these issuers. This access to capital may be further enhanced through listing on particular exchanges, which could affect the level of investors' trust in a listed company's governance structure and the fairness of trading in the company's securities (through the perceived effectiveness of exchanges' conduct rules and surveillance of trading as well as other services and regulatory functions).

Exchanges may try to compete for issuers by reducing listing fees or by improving the quality of services they offer, or both. The cost of listing for an issuer includes listing fees and the cost of complying with listing standards. In principle, this means exchanges can compete by reducing listing fees, by relaxing the listing standards issuers must meet, or by offering several trading segments with different listing standards on each, though such standards must be determined to be substantially similar to a Named Market in order to get the benefit of the Securities Act Section 18(b)(1)(B) exemption from state registration requirements. Any concern that exchanges may try to compete by lowering the listing standards to attract issuers (and hence enter in a ''race-to-the-bottom'') is mitigated by the fact that (1) Listing standards affect exchanges' reputations among investors, which, in turn, impacts their attractiveness to issuers, (2) any proposed listing standards or proposed changes to existing listing standards must be filed with the Commission pursuant to Section 19(b) of the Securities Exchange Act of 1934, as amended (''Exchange Act'') and must meet its requirements to become effective,[80] and (3) lower listing standards that are not substantially similar to those of a Named Market will not have the benefit of the exemption from state registration requirements.[81]

The competition among exchanges for listings is only partially based on price. Exchanges also compete in various other areas, which contribute to the quality of the service listed issuers receive, including, but not limited to, provision of trade statistics, regulatory and surveillance services, access to new technology, attractive trading mechanisms, and marketing services.

One important dimension of competition is brand name.[82] Issuers place high value on being listed on certain exchanges because investors may more readily trust those exchanges, which may, in turn, reduce the cost of raising capital for those issuers. As a result, NYSE and Nasdaq/NGM, which are already the two largest exchanges in terms of securities listed, may be able to charge listing fees that are above marginal cost—that is, what it would cost them to list additional issuers—and higher than other competing exchanges; therefore, certain exchanges may earn economic rent from these higher listing premiums (the amount of fee difference certain exchanges can charge, above a competitor's price, because of its brand name). In addition to brand name recognition, the market for listing exhibits positive network externalities: issuers may prefer to be listed on exchanges where many other issuers are listed and where there are more intermediaries trading because of increased liquidity and visibility.[83] This indicates that, all else being equal, large exchanges (in terms of listings) will tend to be favored over smaller ones. In theory, this preference may persist to some extent even if large exchanges were to offer slightly inferior services than their smaller counterparts because the advantages of being listed on a large exchange, where there are many issuers and intermediaries, might outweigh the cost of being offered slightly inferior services. Because of these brand name effects and positive externalities, the market for listings to some extent exhibits certain barriers to entry for new entrants to the listing markets, such as BATS.[84]

condition of the issuer, cheap stock held by insiders, the quantity of securities subject to options and warrants, self-dealing and other conflicts of interest, and the price at which the securities will be offered. *See id.* Some merit regulation would be imposed on these issuers through application of exchange listing standards.

[77] *See* Securities Exchange Act Release No. 64546, *supra* note 8.

[78] *See, e.g.,* Thierry Foucault and Christine A. Parlour, *Competition for Listing,* 35 Rand J. Econ. 329 (2004) (describing how listing fees and trading costs both affect firms' incentives to list with one exchange versus another).

[79] It has been noted that NYSE and the London Stock Exchange, for example, compete for listings of firms in third countries, in particular from emerging economies. *See* Thomas J. Chemmanur & Paolo Fulghieri, *Competition and Cooperation Among Exchanges: A Theory of Cross-Listing and Endogenous Listing Standards,* 82 J. Fin. Econ. 455, 456 (2006). *See generally* Craig Doidge, Andrew Karolyi, and René Stulz, *Has New York Become Less Competitive than London in Global Markets? Evaluating Foreign Listing Choices Over Time,* Journal of Financial Economics 91, 253–277 (2009); Craig Doidge, Andrew Karolyi, and René Stulz, *Why Do Foreign Firms Leave U.S. Equity Markets?,* Journal of Finance 65, 1507–1553 (2010); Caglio, Cecilia, Hanley, Kathleen Weiss and Marietta-Westberg, Jennifer, *Going Public Abroad: The Role of International Markets for IPOs* (March 16, 2010), *available at* SSRN: *http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1572949.* Additionally, differences in regulatory regimes may impact listing decisions.

[80] Any revision to exchange listing standards must be done in accordance with Section 19(b) of the Exchange Act and Rule 19b–4 thereunder. Any Commission approval of a listing standard revision is conditioned upon a finding by the Commission that the revision is consistent with the requirements of the Exchange Act and rules thereunder. *See* 15 U.S.C. 78s.

[81] *See* Chemmanur & Fulghieri, *supra* note 79, at 458.

[82] *See generally* Clement G. Krouse, *Brand Name as a Barrier to Entry: The Rea Lemon Case,* 51 Southern Econ. J. 495 (1984) (describing the effect of brand name on competition in markets with incomplete information); *see also* Tibor Scitovsky, *Ignorance as a Source of Oligopoly Power,* 40 Amer. Econ. Rev. 48, 49 (1950) (''An ignorant buyer * * * is unable to judge the quality of the products he buys by their intrinsic merit. Unable to appraise products by objective standards, he is forced to base his judgment on indices of quality, such as * * * general reputation of the producing firms.'').

[83] *See, e.g.,* Carmine Di Nola, *Competition and Integration Among Stock Exchanges in Europe: Network Effects, Implicit Mergers and Remote Access,* 7 European Fin. Man. 39 (2001)(''Firms may derive more utility in being listed on exchanges where there are more intermediaries as they give more liquidity to the market.'').

[84] Brand name recognition is frequently recognized as a barrier to entry mainly because consumers do not have all the information regarding product quality and thus tend to rely on brand names as a proxy for quality. *See, e.g., Brand Name as a Barrier to Entry: The Rea Lemon Case,* 51 S. Econ. J. 495 (1984); Tibor Scitovsky, *Ignorance as a Source of Oligopoly Power,* 40 Amer. Econ. Rev. 48 (1950). Network externalities are also recognized as a barrier to entry. *See, e.g.,* Gregory J. Weden, *Network Effects and Conditions of Entry: Lessons from the Microsoft Case,* 69 Antitrust L.J. 87 (2001); Douglas A. Melamed, *Network Industries and Antitrust,* 23 Harv. J. L. & Pub. Pol'y 147 (1999).

B. Benefits, Including the Impact on Efficiency, Competition, and Capital Formation

By proposing to exempt securities listed, or authorized for listing, on BATS from state law registration requirements, the Commission expects that issuers seeking to list securities on BATS could have the benefit of reduced regulatory compliance burdens, as compliance with state blue sky law requirements would not be required. One benefit of this proposal would be to eliminate these compliance burdens with respect to securities listed, or authorized for listing, on BATS. The Commission expects that the proposed rule could also improve efficiency by eliminating duplicative registration costs for issuers and improving liquidity by allowing for greater market access to issuers who have not been listed previously.

To the extent that state merit reviews may have inhibited certain smaller businesses from making public offerings,[85] an exemption from state registration requirements could facilitate capital formation.

The Commission preliminarily believes that the proposed amendment to Rule 146(b) should permit BATS to better compete for listings with other markets whose listed securities already are exempt from state law registration requirements. This result could enhance competition, thus benefiting market participants and the public.

Specifically, BATS currently intends to enter the listing market with generally lower fees than incumbent exchanges in order to compete with them.[86] In response to BATS' proposed entry, although recognizing the significant barriers to entry noted above, the incumbent exchanges might choose to reduce their listing fees to match or come closer to those proposed by BATS. Incumbent exchanges might also enhance the other services they provide to their currently listed issuers (*e.g.,* regulatory and surveillance services, access to new technology, attractive trading mechanisms, marketing services) as a way to counteract BATS' proposed lower listing fees.

Additional competition in the market for listings could enable some issuers, both public and private, that have (1) either not listed on any exchange or (2) have listed on an exchange but have chosen not to list on certain exchanges because of the costs of listing there, to list on any Named or Designated Market due to the potential for lower listing fees across all exchanges. This potentially could result in a lower cost of capital for those issuers that previously had not listed on an exchange and could benefit the current investors in such issuers in the form of higher company value arising from the reduced cost of capital and increased liquidity. If currently unlisted firms were able to list because of lower listing fees, this could also improve efficiency and capital formation since future investors in these issuers would have easier access to invest in them and to further diversify their investment portfolios.

Those issuers that are currently listed on any exchange, including the Named Markets, and that remain listed there, would potentially benefit from any reduced listing fees; however, because any such benefit would come at the expense of the exchange on which they are listed in the form of potentially reduced profit, this aggregate effect would be a transfer from one group of investors (exchange shareholders) to another group of investors (listed issuer shareholders).

Additionally, some issuers currently listed on other Named or Designated Markets could potentially switch their listings to BATS, thus potentially lowering their listing costs (provided the Named or Designated Markets did not reduce their listing fees). The size of any such potential benefit would depend on how large any cost savings due to listing on BATS would be in comparison to the cost of giving up any valuable services that the other exchanges might provide that BATS might not. In addition, the behavior of these issuers would depend heavily on the extent to which these other exchanges respond to BATS' proposed entry by making themselves more competitive to the issuers.

C. Costs, Including the Impact on Efficiency, Competition, and Capital Formation

The proposed amendment would eliminate state registration requirements for securities listed, or authorized for listing, on BATS. In principle, there could be certain economic costs to investors through the loss of benefits of state registration and oversight. For example, by listing on BATS, issuers would no longer be required to comply with certain states' blue sky laws, which could mandate more detailed disclosure than BATS' proposed listing standards and the requirements imposed pursuant to the federal securities laws, rules, and regulations. In such circumstances, investors could lose the benefit of the additional information. Additionally, to the extent blue sky laws result in additional enforcement protections in the form of another regulator policing issuer activity, then investors from these states could incur costs when issuers choose to list on BATS. Some commentators have also expressed a concern that the exemption from blue sky laws could prompt riskier public offerings.[87]

From the perspective of competition in the market for listing, the Commission notes that there could be a concern that, to the extent the market for exchange services exhibits network effects, as explained above, there could be a loss in efficiency as a result of having a greater number of networks, if one or more of the existing large exchanges (in terms of listings) shrinks in size. However, the Commission also notes that the overall efficiency effect would depend on the precise fragmentation of the exchanges. It is possible, for instance, that, through specialization of exchanges, there could be an efficiency gain from having more distinct exchanges, each of which specializes in listing issuers from certain types of industries.

The Commission acknowledges that these costs are difficult to quantify. The Commission believes that Congress contemplated these costs in relation to the economic benefits of exempting Covered Securities from state regulation. The Commission, however, is considering the costs of the proposed

[85] A number of scholarly articles have expressed concerns over the possibility for blue sky merit regulation to hinder capital formation. *See, e.g.,* Martin Fojas, *Ay Dios NSMIA!: Proof of a Private Offering Exemption Should Not Be a Precondition for Preempting Blue Sky Law Under the National Securities Markets Improvement Act,* 74 Brooklyn L. Rev. 477 (2009); Rutheford B. Campbell, Jr., *Blue Sky Laws and the Recent Congressional Preemption Failure,* 22 J. Corp. L. 175 (1997); Brian J. Fahrney, *State Blue Sky Laws: A Stronger Case for Federal Pre-Emption Due to Increasing Internationalization of Securities Markets,* Comment, 86 Nw. U. L. Rev. 753 (1991–92); Roberta S. Karmel, *Blue-Sky Merit Regulation: Benefit to Investors or Burden on Commerce,* 53 Brook. L. Rev. 106 (1987–88). While the concerns are numerous, other studies have shown some positive effect of merit regulation. *See* Jay T. Brandi, *The Silverlining in Blue Sky Laws: The Effect of Merit Regulation on Common Stock Returns and Market Efficiency,* 12 J. Corp. L. 713 (1986–87) (reporting that merit regulation can have a positive effect on investor returns); Ashwini K. Agrawal, ''The Impact of Investor Protection Law on Corporate Policy: Evidence from the Blue Sky Laws,'' working paper (2009) (reporting that the passage of investor protection statutes causes firms to pay out greater dividends, issue more equity, and grow in size), *available at http://ssrn.com/abstract=1442224.* Some merit regulation would be imposed on these issuers through application of exchange listing standards.

[86] *See* Securities Exchange Act Release No. 64546, *supra* note 8, 76 FR at 31666 & n. 27–28 (representing that BATS' proposed pricing, while not necessarily cheaper for all issuers at all other markets, is roughly equivalent to or less than the price issuers would pay at other exchanges, including NGM and NCM).

[87] *See, e.g.,* Brandi, *supra* note 85.

amendment to Rule 146(b) and requests commenters to provide views and supporting information as to the costs and benefits associated with this proposal. The proposed rule otherwise imposes no recordkeeping or compliance burdens, but would provide a limited purpose exemption under the federal securities laws.

Overall, the Commission believes the proposed amendment to Rule 146(b) should not impair efficiency, competition, and capital formation.

D. Request for Comment

We request comment on the costs and benefits associated with this rule amendment, including identification and assessments of any costs and benefits not discussed in this analysis. We solicit comments on the usefulness of the rule amendment to investors, reporting persons, registrants, and the marketplace at large. We encourage commentators to identify, discuss, analyze, and supply relevant data, information, or statistics regarding any such costs or benefits, as well as any costs and benefits not already defined. We also request qualitative feedback on the nature of the benefits and costs described above. Additionally, we request comment on the extent of any costs that may be attributable to any loss of protections that currently are afforded by the state registration process, such as any merit-based requirements imposed by states on issuers.

VII. Regulatory Flexibility Act Certification

Section 603(a) of the Regulatory Flexibility Act [88] requires the Commission to undertake an initial regulatory flexibility analysis of the proposed amendment to Rule 146 on small entities, unless the Commission certifies that the proposed amendment, if adopted, would not have a significant economic impact on a substantial number of small entities.[89] For purposes of Commission rulemaking in connection with the Regulatory Flexibility Act, an issuer is a small business if its ''total assets on the last day of its most recent fiscal year were $5 million or less.'' [90]

The Commission believes that the proposal to amend Rule 146(b) would not affect a substantial number of small entities because, as proposed by BATS, to list its securities on BATS, an issuer's aggregate market value of publicly held shares would be required to be at least $5 million. If an entity's market value of publicly held shares were at least $5 million, it is reasonable to believe that its assets generally would be worth more than $5 million. Therefore, an entity seeking to list securities as proposed by BATS in its proposed listing standards generally would have assets with a market value of more than $5 million and thus would not be a small entity.

Accordingly, the Commission hereby certifies, pursuant to Section 605(b) of the Regulatory Flexibility Act,[91] that amending Rule 146(b) as proposed would not have a significant economic impact on a substantial number of small entities. The Commission encourages written comments regarding this certification. The Commission solicits comment as to whether the proposed amendment to Rule 146(b) could have an effect that has not been considered. The Commission requests that commenters describe the nature of any impact on small entities and provide empirical data to support the extent of such impact.

VIII. Small Business Regulatory Enforcement Fairness Act of 1996

For purposes of the Small Business Enforcement Fairness Act of 1996, a rule is ''major'' if it results or is likely to result in:

(i) An annual effect on the economy of $100 million or more;

(ii) A major increase in costs or prices for consumers or individual industries; or

(iii) Significant adverse effects on competition, investment, or innovation.[92]

The Commission requests comment regarding the potential impact of the proposed amendment on the economy on an annual basis. Commenters should provide empirical data to support their views to the extent possible.

IX. Statutory Authority and Text of the Proposed Rule

The Commission is proposing an amendment to Rule 146 pursuant to the Securities Act of 1933,[93] particularly Sections 18(b)(1)(B) and 19(a).[94]

List of Subjects in 17 CFR Part 230

Securities.

For the reasons set forth in the preamble, the Commission proposes to amend Title 17, Chapter II of the Code of Federal Regulations as follows:

PART 230—GENERAL RULES AND REGULATIONS, SECURITIES ACT OF 1933

1. The authority citation for Part 230 continues to read, in part, as follows:

Authority: 15 U.S.C. 77b, 77c, 77d, 77f, 77g, 77h, 77j, 77r, 77s, 77z–3, 77sss, 78c, 78d, 78j, 78*l,* 78m, 78n, 78o, 78t, 78w, 78*ll*(d), 78mm, 80a–8, 80a–24, 80a–28, 80a–29, 80a–30, and 80a–37, unless otherwise noted.

* * * * *

2. Revise Section 230.146(b)(1) and (b)(2) to read as follows:

§ 230.146 Rules under section 18 of the Act.

* * * * *

(b) * * *

(1) For purposes of Section 18(b) of the Act (15 U.S.C. 77r), the Commission finds that the following national securities exchanges, or segments or tiers thereof, have listing standards that are substantially similar to those of the New York Stock Exchange (''NYSE''), the NYSE Amex LLC (''NYSE Amex''), or the National Market System of the Nasdaq Stock Market (''Nasdaq/NGM''), and that securities listed, or authorized for listing, on such exchanges shall be deemed covered securities:

(i) Tier I of the NYSE Arca, Inc.;

(ii) Tier I of the NASDAQ OMX PHLX LLC;

(iii) The Chicago Board Options Exchange, Incorporated;

(iv) Options listed on the International Securities Exchange, LLC;

(v) The Nasdaq Capital Market; and

(vi) BATS Exchange, Inc.

(2) The designation of securities in paragraphs (b)(1)(i) through (vi) of this section as covered securities is conditioned on such exchanges' listing standards (or segments or tiers thereof) continuing to be substantially similar to those of the NYSE, NYSE Amex, or Nasdaq/NGM.

* * * * *

By the Commission.

Dated: August 8, 2011.

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20445 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

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[88] 5 U.S.C. 603(a).

[89] 5 U.S.C. 605(b).

[90] 17 CFR 230.157. *See also* 17 CFR 240.0–10(a).

[91] 5 U.S.C. 605(b).

[92] Public Law 104–121, Title II, 110 Stat. 857 (1996) (codified in various sections of 5 U.S.C., 15 U.S.C., and as a note to 5 U.S.C. 601).

[93] 15 U.S.C. 77a *et seq.*

[94] 15 U.S.C. 77r(b)(1)(B) and 77s(a).

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 73

[Docket Nos. FDA–2011–C–0344 and FDA–2011–C–0463]

CooperVision, Inc.; Filing of Color Additive Petitions

Correction

In proposed rule document 2011–16089 appearing on page 37690 in the issue of Tuesday, June 28, 2011, make the following correction:

On page 37690, in the first column, in the twelfth line from the bottom of the page, ''methacryloxyethyl)phenstyamino]'' should read ''methacryloxyethyl)phenlyamino]''.

[FR Doc. C1–2011–16089 Filed 8–10–11; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 101

[Docket Nos. FDA–2000–P–0102, FDA–2000–P–0133, and FDA–2006–P–0033]

Food Labeling; Health Claim; Phytosterols and Risk of Coronary Heart Disease; Reopening of the Comment Period

AGENCY: Food and Drug Administration, HHS.

ACTION: Proposed rule; reopening of comment period.

SUMMARY: The Food and Drug Administration (FDA) is reopening the comment period for the proposed rule published in the **Federal Register** of December 8, 2010, proposing to amend regulations on plant sterol/stanol esters and risk of coronary heart disease (CHD). FDA is reopening the comment period because the Agency received a request for additional time to comment on the proposed rule.

DATES: The comment period for the proposed rule published December 8, 2010 (75 FR 76526), is reopened. Submit either electronic or written comments by October 25, 2011.

ADDRESSES: Submit electronic comments *http://www.regulations.gov.* Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Blakeley Fitzpatrick, Center for Food Safety and Applied Nutrition (HFS–830), 5100 Paint Branch Pkwy., College Park, MD 20740, 240–402–2176.

SUPPLEMENTARY INFORMATION:

I. Background

In the **Federal Register** of December 8, 2010 (75 FR 76526), FDA proposed to amend its regulations in § 101.83 (21 CFR 101.83) on plant sterol/stanol esters and risk of CHD (the phytosterols proposed rule). Among other revisions, the Agency proposed to: (1) Adopt the term ''phytosterols'' as inclusive of both plant sterols and stanols; (2) permit claims on products with phytosterols, derived from either vegetable oils or tall oils, containing at least 80 percent of beta-sitosterol, campesterol, stigmasterol, sitostanol, and/or campestanol (combined weight); (3) replace the analytical methods FDA uses to determine the amount and nature of the substance with the Sorenson and Sullivan method for evaluation of campesterol, stigmasterol, and beta-sitosterol in those foods for which the method has been validated; (4) revise the daily dietary intake of phytosterols necessary to justify the CHD risk reduction claim (2 grams (g) per day) and the minimum amount of phytosterols (non-esterified weight) required to be in a serving of the food (0.5 g per reference amount customarily consumed (RACC)); (5) for conventional food, limit the use of the claim to the food uses of phytosterols that have been submitted to FDA in a generally recognized as safe notification to which the Agency had no further questions and where the conditions of use are consistent with the eligibility requirements for the health claim; (6) remove the requirement that the health claim include a recommendation that phytosterols be consumed in two servings eaten at different times of the day, but require that the substance be taken with meals or snacks; (7) eliminate the enumeration of specific conventional foods eligible to bear the claim; (8) allow for the use of the health claim on phytosterol ester-containing dietary supplements (esterified with food-grade fatty acids) but not on nonesterified phytosterol-containing dietary supplements; (9) clarify that the limited exemption from the total fat disqualifying level of more than 13 g total fat per 50 g of food when the RACC is 30 g or less or 2 tablespoons or less applies to vegetable oil spreads resembling margarine; (10) permit liquid vegetable oils to be exempt from the total fat disqualifying level on a per RACC, per labeled serving size, and per 50 g basis; and (11) permit liquid vegetable oils to be exempt from the minimum nutrient requirement and vegetable oil spreads resembling margarine to meet the 10 percent minimum nutrient requirement by the addition of Vitamin A consistent with FDA's fortification policy.

Interested persons were originally given until February 22, 2011, to comment on the proposed rule.

II. Request for Comments

After publication of the phytosterols proposed rule, the Agency received two petitions for an administrative stay of action and two letters requesting that FDA extend its enforcement discretion based on FDA's February 14, 2003, letter of enforcement discretion to Cargill Health and Food Technologies. Based on concerns that 75 days was not enough time for industry to come into compliance with § 101.83 or to make the claim consistent with the proposed requirements in the phytosterols proposed rule, the Agency issued, in the **Federal Register** of February 18, 2011, an extension of its enforcement discretion based on the February 14, 2003, letter (76 FR 9525).

On February 10, 2011, the Agency received a comment on the phytosterols proposed rule by Venable LLP requesting an extension of the comment period until April 23, 2011, because the period of time allowed for comment did not provide enough time for them to collect, assess, and comment on the relevant data regarding the cholesterol-lowering efficacy of nonesterified phytosterols in dietary supplements. FDA did not respond to Venable LLP's request within the comment period and cannot extend a closed comment period. However, the Agency is reopening the comment period for this rule in response to Venable LLP's request. The Agency recognizes that additional time to review and comment on the data related to the relationship between nonesterified phytosterols and reduced risk of CHD would be helpful and consistent with sound public policy, therefore FDA is reopening the comment period for all interested persons on the phytosterols proposed rule to allow for comments to be submitted to the docket.

Following receipt of comments on this document, FDA intends to publish a final rule, which will amend § 101.83. The reopening of the comment period may result in the submission of additional information that may cause the Agency to reconsider its proposed amendments to the phytosterols and risk of coronary heart disease health claim. The Agency notes that a final rule may vary from the proposal. To the extent that manufacturers have labeled their products consistent with the proposed requirements, and the final requirements differ from what the Agency proposed, manufacturers will be required to change their labels to conform to the final rule.

III. How To Submit Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) either electronic or written comments regarding this document. It is only necessary to send one set of comments. It is no longer necessary to send two copies of mailed comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

Dated: August 8, 2011.

Leslie Kux,

Acting Assistant Commissioner for Policy.

[FR Doc. 2011–20406 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R07–OAR–2011–0470, FRL–9450–8]

Approval and Promulgation of Implementation Plans; Iowa: Prevention of Significant Deterioration; Greenhouse Gas Permitting Authority and Tailoring Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve a revision to the Iowa State Implementation Plan (SIP) relating to regulation of Greenhouse Gases (GHGs) under Iowa's Prevention of Significant Deterioration (PSD) program. This revision was submitted by the Iowa Department of Natural Resources (IDNR) to EPA on December 22, 2010. It is intended to align Iowa's regulations with the ''PSD and Title V Greenhouse Gas Tailoring Final Rule.'' EPA is proposing to approve the revision because the Agency has made the preliminary determination that the SIP revision, already adopted by Iowa as a final effective rule, is in accordance with the Clean Air Act (CAA or Act) and EPA regulations regarding PSD permitting for GHGs.

DATES: Comments must be received on or before September 12, 2011.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R07–OAR–2011–0470, by one of the following methods:

1. *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
2. *E-mail: gonzalez.larry@epa.gov.*
3. *Fax:* (913) 551–7844.
4. *Mail:* Air Planning and Development Branch, Air and Waste Management Division, U.S. Environmental Protection Agency, Region 7, 901 North 5th Street, Kansas City, Kansas 66101.
5. *Hand Delivery or Courier:* Mr. Larry Gonzalez, Air Planning and Development Branch, Air and Waste Management Division, U.S. Environmental Protection Agency, Region 7, 901 North 5th Street, Kansas City, Kansas 66101. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8 a.m. to 4:30 p.m., excluding Federal holidays.

Instructions: Direct your comments to Docket ID No. EPA–R07–OAR–2011–0470. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit through *http://www.regulations.gov* or e-mail, information that you consider to be CBI or otherwise protected. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the electronic docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, i.e., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Planning and Development Branch, Air and Waste Management Division, U.S. Environmental Protection Agency, Region 7, 901 North 5th Street, Kansas City, Kansas 66101. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: For information regarding the Iowa SIP, contact Mr. Larry Gonzalez, Air Planning and Development Branch, Air and Waste Management Division, U.S. Environmental Protection Agency, Region 7, 901 North 5th Street, Kansas City, Kansas 66101. Mr. Gonzalez's telephone number is (913) 551–7047; *e-mail address: gonzalez.larry@epa.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. What action is EPA proposing in today's notice?

On December 22, 2010, IDNR submitted a request to EPA to approve revisions to the State's SIP and Title V program to incorporate recent rule amendments adopted by the Iowa Environmental Protection Commission. These adopted rules became effective in the Iowa Administrative Code on that date. These amendments establish thresholds for GHG emissions in Iowa's PSD and Title V regulations at the same emissions thresholds and in the same time-frames as those specified by EPA in the ''PSD and Title V Greenhouse Gas Tailoring Final Rule'' (75 FR 31514), hereafter referred to as the ''Tailoring Rule,'' ensuring that smaller GHG sources emitting less than these thresholds will not be subject to permitting requirements for GHGs that they emit. The amendments to the SIP clarify the applicable thresholds in the Iowa SIP, address the flaw discussed in the ''Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans Final Rule,'' 75 FR 82536 (December 30, 2010) (the ''PSD SIP Narrowing Rule''), and incorporate state rule changes adopted at the state level into the Federally-approved SIP. In today's notice, pursuant to section 110 of the CAA, EPA is proposing to approve these revisions into the Iowa SIP.[1]

II. What is the background for the PSD SIP approval proposed by EPA in today's notice?

This section briefly summarizes EPA's recent GHG-related actions that provide the background for today's proposed actions. More detailed discussion of the background is found in the preambles for those actions. In particular, the background is contained in what we called the PSD SIP Narrowing Rule,[2] and in the preambles to the actions cited therein.

A. GHG-Related Actions

EPA has recently undertaken a series of actions pertaining to the regulation of GHGs that, although for the most part distinct from one another, establish the overall framework for today's proposed action on the Iowa SIP. Four of these actions include, as they are commonly called, the ''Endangerment Finding'' and ''Cause or Contribute Finding,'' which EPA issued in a single final action,[3] the ''Johnson Memo Reconsideration,''[4] the ''Light-Duty Vehicle Rule,''[5] and the ''Tailoring Rule.'' Taken together and in conjunction with the CAA, these actions established regulatory requirements for GHGs emitted from new motor vehicles and new motor vehicle engines; determined that such regulations, when they took effect on January 2, 2011, subjected GHGs emitted from stationary sources to PSD requirements; and limited the applicability of PSD requirements to GHG sources on a phased-in basis. EPA took this last action in the Tailoring Rule, which, more specifically, established appropriate GHG emission thresholds for determining the applicability of PSD requirements to GHG-emitting sources.

PSD is implemented through the SIP system. In December 2010, EPA promulgated several rules to implement the new GHG PSD SIP program. Recognizing that some states had approved SIP PSD programs that did not apply PSD to GHGs, EPA issued a SIP Call and, for some of these states, a Federal Implementation Plan (FIP).[6] Recognizing that other states had approved SIP PSD programs that do apply PSD to GHGs, but that do so for sources that emit as little as 100 or 250 tpy of GHG, and that do not limit PSD applicability to GHGs to the higher thresholds in the Tailoring Rule, EPA issued the PSD SIP Narrowing Rule. Under that rule, EPA withdrew its approval of the affected SIPs to the extent those SIPs covered GHG-emitting sources below the Tailoring Rule thresholds. EPA based its action primarily on the ''error correction'' provisions of CAA section 110(k)(6).

B. Iowa's Actions

On July 20, 2010, Iowa provided a letter to EPA, in accordance with a request to all states from EPA in the Tailoring Rule, with confirmation that the State of Iowa has the authority to regulate GHGs in its PSD program. The letter also confirmed Iowa's intent to amend its air quality rules for the PSD program for GHGs to match the thresholds set in the Tailoring Rule. See the docket for this proposed rulemaking for a copy of Iowa's letter.

In the PSD SIP Narrowing Rule, published on December 30, 2010, EPA withdrew its approval of Iowa's SIP (among other SIPs) to the extent that the SIP applies PSD permitting requirements to GHG emissions from sources emitting at levels below those set in the Tailoring Rule.[7] As a result, Iowa's current approved SIP provides the State with authority to regulate GHGs, but only at and above the Tailoring Rule thresholds; and requires new and modified sources to receive a Federal PSD permit based on GHG emissions only if they emit or have potential to emit at or above the Tailoring Rule thresholds.

The basis for this proposed SIP revision is that limiting PSD applicability to GHG sources to the higher thresholds in the Tailoring Rule is consistent with the SIP provisions that require assurances of adequate resources, and thereby addresses the flaw in the SIP that led to the PSD SIP Narrowing Rule. Specifically, CAA section 110(a)(2)(E) includes as a requirement for SIP approval that states provide ''necessary assurances that the State * * * will have adequate personnel [and] funding * * * to carry out such [SIP].'' In the Tailoring Rule, EPA established higher thresholds for PSD applicability to GHG-emitting sources on grounds that the states generally did not have adequate resources to apply PSD to GHG-emitting sources below the Tailoring Rule thresholds,[8] and no state, including Iowa, asserted that it did have adequate resources to do so.[9] In the PSD SIP Narrowing Rule, EPA found that the affected states, including Iowa, had a flaw in their SIP at the time they submitted their PSD programs, which was that the applicability of the PSD programs was potentially broader than the resources available to them under

[1] EPA intends to address Iowa's December 22, 2010, request to approve revisions to the Title V program relating to GHGs in a subsequent rulemaking.

[2] ''Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans; Final Rule.'' 75 FR 82536 (December 30, 2010).

[3] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act.'' 74 FR 66496 (December 15, 2009).

[4] ''Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs.'' 75 FR 17004 (Apr. 2, 2010).

[5] ''Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule.'' 75 FR 25324 (May 7, 2010).

[6] Specifically, by action dated December 13, 2010, EPA finalized a ''SIP Call'' that would require those states with SIPs that have approved PSD programs but do not authorize PSD permitting for GHGs to submit a SIP revision providing such authority. ''Action To Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call,'' 75 FR 77698 (December 13, 2010). EPA made findings of failure to submit in some states which were unable to submit the required SIP revision by their deadlines, and finalized FIPs for such states. *See, e.g.* ''Action To Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Failure To Submit State Implementation Plan Revisions Required for Greenhouse Gases,'' 75 FR 81874 (December 29, 2010); ''Action To Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Federal Implementation Plan,'' 75 FR 82246 (December 30, 2010). Because Iowa's SIP already authorizes Iowa to regulate GHGs once GHGs became subject to PSD requirements on January 2, 2011, Iowa is not subject to the SIP Call or FIP.

[7] ''Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans; Final Rule.'' 75 FR 82536 (December 30, 2010).

[8] Tailoring Rule, 75 FR at 31517.

[9] PSD SIP Narrowing Rule, 75 FR at 82540.

their SIP.[10] Accordingly, for each affected state, including Iowa, EPA concluded that EPA's action in approving the SIP was in error, under CAA section 110(k)(6), and EPA rescinded its approval to the extent the PSD program applies to GHG-emitting sources below the Tailoring Rule thresholds.[11] EPA recommended that states adopt a SIP revision to incorporate the Tailoring Rule thresholds, thereby (i) assuring that under state law, only sources at or above the Tailoring Rule thresholds would be subject to PSD; and (ii) avoiding confusion under the Federally approved SIP by clarifying that the SIP applies to only sources at or above the Tailoring Rule thresholds.[12]

III. What is EPA's analysis of Iowa's proposed SIP revision?

On December 22, 2010, IDNR submitted a revision of its regulations to EPA for processing and approval into the SIP. This SIP revision puts in place the GHG emission thresholds for PSD applicability set forth in EPA's Tailoring Rule. EPA's approval of Iowa's SIP revision will incorporate the revisions of the Iowa regulations into the Federally-approved SIP. Doing so will clarify the applicable thresholds in the Iowa SIP.

The State of Iowa's December 22, 2010, proposed SIP revision establishes thresholds for determining which stationary sources and modification projects become subject to permitting requirements for GHG emissions under Iowa's PSD program. Specifically, Iowa's December 22, 2010, proposed SIP revision includes changes—which are already effective—to Iowa's Administrative Code, revising the subrule 33.3(1) definition of ''regulated New Source Review (NSR) pollutant'' to specifically define the term ''subject to regulation'' for the PSD program, and to define ''greenhouse gases (GHGs)'' and ''tpy CO_2 equivalent emissions (CO_2e).'' Additionally, the amendments to subrule 33.3(1) specify the methodology for calculating an emissions increase for GHGs, the applicable thresholds for GHG emissions subject to PSD, and the schedule for when the applicability thresholds take effect.

Iowa is currently a SIP-approved State for the PSD program, and has previously incorporated EPA's 2002 NSR reform revisions for PSD into its SIP. *See* 72 FR 27056 (May 14, 2007). The changes to Iowa's PSD program regulations are substantively the same as the Federal provisions amended in EPA's Tailoring Rule. As part of its review of Iowa's submittal, EPA performed a line-by-line review of Iowa's proposed revision and has preliminarily determined that it is consistent with the Tailoring Rule.

IV. Proposed Action

Pursuant to section 110 of the CAA, EPA is proposing to approve Iowa's December 22, 2010 revisions to the Iowa SIP, relating to PSD requirements for GHG-emitting sources. Specifically, Iowa's December 22, 2010, proposed SIP revision establishes appropriate emissions thresholds for determining PSD applicability to new and modified GHG-emitting sources in accordance with EPA's Tailoring Rule. EPA has made the preliminary determination that this SIP revision is approvable because it is in accordance with the CAA and EPA regulations regarding PSD permitting for GHGs.

If EPA does approve Iowa's changes to its air quality regulations to incorporate appropriate thresholds for GHG permitting applicability into Iowa's SIP, then section 52.822(b) of 40 CFR part 52, as included in EPA's PSD SIP Narrowing Rule—which codifies EPA's limiting its approval of Iowa's PSD SIP to not cover the applicability of PSD to GHG-emitting sources below the Tailoring Rule thresholds—is no longer necessary. In today's proposed action, EPA is also proposing to amend section 52.822(b) of 40 CFR part 52 to remove this unnecessary regulatory language.

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k), 7661a(d); 40 CFR 52.02(a); 40 CFR 70.1(c). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this proposed action merely approves the State's law as meeting Federal requirements and does not impose additional requirements beyond those imposed by the State's law. For that reason, the proposed approvals of Iowa's revision to its SIP relating to GHGs:

- Are not ''significant regulatory actions'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and are therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011);
- Do not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Are certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Do not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Do not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Are not economically significant regulatory actions based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Are not significant regulatory actions subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Are not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Do not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this proposed rule does not have Tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP program is not approved to apply in Indian country located in the State, and EPA notes that it will not impose substantial direct costs on Tribal governments or preempt Tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, and Reporting and recordkeeping requirements.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: August 3, 2011.

Karl Brooks,

Regional Administrator, Region 7.

[FR Doc. 2011–20455 Filed 8–10–11; 8:45 am]

BILLING CODE 6560–50–P

[10] *Id.* at 82542.

[11] *Id.* at 82544.

[12] *Id.* at 82540.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R02–OAR–2011–0607, FRL–9450–9]

Approval and Promulgation of Air Quality Implementation Plans; State of New Jersey; Regional Haze State Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve the revision to the State Implementation Plan submitted by the State of New Jersey on July 28, 2009, and supplemented on December 9, 2010, and March 2, 2011, that addresses regional haze for the first planning period from 2008 through 2018. This revision addresses the requirements of the Clean Air Act and EPA's rules that require states to prevent any future, and remedy any existing, anthropogenic impairment of visibility in mandatory Class I areas caused by emissions of air pollutants located over a wide geographic area (also referred to as the ''regional haze program''). States are required to assure reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas. This plan protects and improves visibility levels in New Jersey's Class I area, the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge, as well as other Class I areas in the Northeast United States. New Jersey's SIP is in two parts: Reasonable Progress and application of Best Available Retrofit Control Technology. EPA is proposing to approve the Reasonable Progress portion of the plan, since New Jersey has adopted all of the reasonably available measures recommended by the states during the development of the SIP. EPA is proposing approval of New Jersey's plans to implement Best Available Retrofit Technologies on eligible sources, as well New Jersey's Subchapter 9, Sulfur in Fuels.

DATES: Comments must be received on or before September 12, 2011.

ADDRESSES: Submit your comments, identified by Docket Number EPA–R02–OAR–2011–0607, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: Werner.Raymond@epa.gov.*
- *Fax:* 212–637–3901.
- *Mail:* Raymond Werner, Chief, Air Programs Branch, Environmental Protection Agency, Region 2 Office, 290 Broadway, 25th Floor, New York, New York 10007–1866.
- *Hand Delivery:* Raymond Werner, Chief, Air Programs Branch, Environmental Protection Agency, Region 2 Office, 290 Broadway, 25th Floor, New York, New York 10007–1866. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30 excluding Federal holidays.

Instructions: Direct your comments to Docket No. EPA–R02–OAR–2011–0607. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters or any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/air/docket.html.*

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FOR FURTHER INFORMATION CONTACT: Robert F. Kelly, State Implementation Planning Section, Air Programs Branch, EPA Region 2, 290 Broadway, New York, New York 10007–1866. The telephone number is (212) 637–4049. Mr. Kelly can also be reached via electronic mail at *kelly.bob@epa.gov.*

SUPPLEMENTARY INFORMATION:

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Throughout this document, wherever ''Agency,'' ''we,'' ''us,'' or ''our'' is used, we mean the EPA.

I. What action is EPA proposing?

EPA is proposing to approve the State of New Jersey's (New Jersey's) July 28, 2009 State Implementation Plan (SIP) revision addressing regional haze under the Clean Air Act (CAA or the Act) sections 301(a) and 110(k)(3). New Jersey's Regional Haze SIP revision implements all measures determined by the State to be reasonable and addresses New Jersey's Reasonable Progress Goals (RPG), as required by the Act. RPGs are interim visibility goals towards meeting the national visibility goal. New Jersey's Regional Haze SIP revision also implements Best Available Retrofit Control Technology (BART) on eligible facilities subject to the regional haze program.

Consistent with EPA guidance and regulations, (see 70 FR 39104, 39106 (July 6, 2005)), many states relied on EPA's Clean Air Interstate Rule (CAIR) to satisfy key elements of Regional Haze SIPs. The D.C. Circuit, however, found CAIR to be inconsistent with the requirements of the Act and remanded the rule to the Agency. *North Carolina* v. *EPA,* 531 F.3d 896, 929–30 (D.C. Cir. 2008); modified on rehearing, *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008). In response to the remand of the CAIR rule, on July 6, 2011 EPA finalized the Cross-State Air Pollution Rule (CSAPR); a rule intended to reduce the interstate transport of fine particulate matter and ozone, located at *http://www.epa.gov/crossstaterule.*

Although New Jersey was subject to CAIR, its Regional Haze SIP did not rely on CAIR to meet the requirements for BART or for attaining the in-state emissions reductions necessary to ensure reasonable progress, instead, New Jersey evaluated controls for its potential BART sources. New Jersey made BART determinations for its BART-eligible sources, including Electric Generating Units (EGUs) that might have been controlled under CAIR. Similarly, its long-term strategy for attaining the RPG at the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge (Brigantine) includes controls on EGUs in New Jersey. Therefore, the remand of CAIR has no negative effect on the amount of emission reductions New Jersey will achieve from its Regional Haze SIP revision. This action and the accompanying Technical Support Document (TSD) explain the basis for EPA's proposed approval of New Jersey's Regional Haze SIP revision proposal.

New Jersey has met all of its obligations with respect to the Regional Haze SIP requirements, including the recommendation[1] of the Mid-Atlantic/Northeast Visibility Union (MANE–VU) regional planning organization. New Jersey should not be required to substitute for any emissions shortfalls in other states' plans, especially if other states expected that EPA's CAIR program would be available as part of their RPGs or their BART controls. Therefore, EPA proposes to approve New Jersey's Regional Haze SIP revision, since it adopts all the measures determined to be reasonable by New Jersey, as evaluated by the states working together through MANE–VU.

II. What is the background for EPA's proposed action?

Regional haze is visibility impairment that is produced by many sources and activities which are located across a broad geographic area and emit fine particles and their precursors (*e.g.,* sulfur dioxide, nitrogen oxides, and in some cases, ammonia and volatile organic compounds). Fine particle precursors react in the atmosphere to form fine particulate matter ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon, elemental carbon, and soil dust), which also impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. Visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas, many of which are also referred to as Federal Class I areas.

In the 1977 Amendments to the CAA, Congress initiated a program for protecting visibility in the nation's national parks and wilderness areas. Section 169A(a)(1) of the Act establishes as a national goal the ''prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution.'' In 1990 Congress added section 169B to the Act to address regional haze issues. On July 1, 1999 EPA promulgated the Regional Haze Rule (RHR) (64 FR 35713). The requirement to submit a Regional Haze SIP applies to New Jersey and all 50 states, the District of Columbia and the Virgin Islands. 40 CFR 51.308(b) of the RHR required states to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.

On January 15, 2009, EPA issued a finding that New Jersey failed to submit the Regional Haze SIP. New Jersey subsequently submitted its Regional Haze SIP on July 28, 2009. EPA's January 15, 2009 finding established a two-year deadline of January 15, 2011 for EPA to either approve New Jersey's Regional Haze SIP, or adopt a Federal implementation plan. This proposed action is intended to address the January 15, 2009 finding.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, EPA has encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were developed to address regional haze and related issues. New Jersey participates in the MANE–VU RPO, which also includes the state and tribal governments of Connecticut, Delaware, District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New York, Pennsylvania, Rhode Island, Vermont, the Penobscot Nation, and the St. Regis Mohawk Tribe.

III. What are the requirements for Regional Haze SIPs?

The following is a basic explanation of the RHR. See 40 CFR 51.308 for a complete listing of the regulations under which this SIP revision was evaluated.

A. The Act and the Regional Haze Rule (RHR)

Regional haze SIPs must assure reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas. Section 169A of the Act and EPA's implementing regulations require states to establish long-term strategies for making reasonable progress toward meeting this goal. Implementation plans must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, and require these sources, where appropriate, to install BART controls for the purpose of eliminating or reducing

[1] On June 20, 2007, MANE–VU adopted two documents which provide the technical basis for consultation among the interested parties and define the basic strategies for controlling pollutants that cause visibility impairment at Class I areas in the eastern United States. The documents, entitled ''Statement of the Mid-Atlantic/Northeast Visibility Union (MANE–VU) Concerning a Course of Action within MANE–VU toward Assuring Reasonable Progress,'' and ''Statement of the Mid-Atlantic/Northeast Visibility Union (MANE–VU) Concerning a Request for a Course of Action by States outside of MANE–VU toward Assuring Reasonable Progress'' are together known as the MANE–VU ''Ask.''

visibility impairment. The specific regional haze SIP requirements are discussed in further detail below.

B. Determination of Baseline, Natural, and Current Visibility Conditions

The RHR establishes the deciview (dv) as the principal metric for measuring visibility. This visibility metric expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility is determined by measuring the visual range, which is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky. The dv is calculated from visibility measurements. Each dv change is an equal incremental change in visibility perceived by the human eye. For this reason, EPA believes it is a useful measure for tracking progress in improving visibility. Most people can detect a change in visibility at one dv.[2]

The dv is used in expressing RPGs (which are interim visibility goals towards meeting the national visibility goal), defining baseline, current, and natural conditions, and tracking changes in visibility. The regional haze SIPs must contain measures that ensure ''reasonable progress'' toward the national goal of preventing and remedying visibility impairment in Class I areas caused by manmade air pollution by reducing anthropogenic emissions that cause regional haze. The national goal is a return to natural conditions, *i.e.,* manmade sources of air pollution would no longer impair visibility in Class I areas.

To track changes in visibility over time at each of the 156 Class I areas covered by the visibility program (40 CFR 81.401–437) and as part of the process for determining reasonable progress, the RHR requires states to calculate the degree of existing visibility impairment at each Class I area at the time of each regional haze SIP submittal and periodically review progress every five years midway through each 10-year planning period. To do this, the RHR requires states to determine the degree of impairment (in dv) for the average of the 20 percent least impaired (''best'') and 20 percent most impaired (''worst'') visibility days over a specified time period at each of their Class I areas. In addition, the RHR requires states to develop an estimate of natural visibility conditions for the purposes of comparing progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. EPA has provided guidance to states regarding how to calculate baseline, natural and current visibility conditions.[3]

For the initial regional haze SIPs that were due by December 17, 2007, baseline visibility conditions were used as the starting points for assessing current visibility impairment. Baseline visibility conditions represent the degree of impairment for the 20 percent least impaired days and 20 percent most impaired days at the time the regional haze program was established. Using monitoring data for 2000 through 2004, the RHR required states to calculate the average degree of visibility impairment for each Class I area, based on the average of annual values over the five year period. The comparison of initial baseline visibility conditions to natural visibility conditions indicates the amount of improvement necessary to attain natural visibility, while the future comparison of baseline conditions to the then current conditions will indicate the amount of progress made. In general, the 2000–2004 baseline period is considered the time from which improvement in visibility is measured.

C. Determination of Reasonable Progress Goals (RPGs)

The submission of a series of regional haze SIPs from the states that establish RPGs for Class I areas for each (approximately) 10-year planning period is the vehicle for ensuring continuing progress towards achieving the natural visibility goal. The RHR does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for ''reasonable progress'' toward achieving natural (*i.e.,* ''background'') visibility conditions. In setting RPGs, states must provide for an improvement in visibility for the most impaired days over the (approximately) 10-year period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period.

States have significant discretion in establishing RPGs, but are required to consider the following factors established in the Act and in EPA's RHR: (1) The costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. States must demonstrate in their SIPs how these factors are considered when selecting the RPGs for the best and worst days for each applicable Class I area. (See 40 CFR 51.308(d)(1)(i)(A)). States have considerable flexibility in how they take these factors into consideration, as noted in our Reasonable Progress guidance.[4] In setting the RPGs, states must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to as the ''uniform rate of progress'' or the ''glidepath'') and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the SIP. In setting RPGs, each state with one or more Class I areas (''Class I State'') must also consult with potentially ''contributing states,'' *i.e.,* other nearby states with emission sources that may be affecting visibility impairment at the Class I State's areas. (40 CFR 51.308(d)(1)(iv)).

D. Best Available Retrofit Control Technology (BART)

Section 169A of the Act directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, the Act requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing stationary sources[5] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Control Technology (BART)'' as determined by the state. (CAA 169A(b)(2)(A)). States are directed to conduct BART determinations for such sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Rather than requiring source-specific BART controls, states

[2] The preamble to the RHR provides additional details about the deciview (64 FR 35714, 35725 (July 1, 1999)).

[3] *Guidance for Estimating Natural Visibility conditions under the Regional Haze Rule,* September 2003, (EPA–454/B–03–005 located at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf*), (hereinafter referred to as ''EPA's 2003 Natural Visibility Guidance''), and *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA–454/B–03–004 September 2003 located at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf*)), (hereinafter referred to as ''EPA's 2003 Tracking Progress Guidance'').

[4] *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* (''EPA's Reasonable Progress Guidance''), July 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10 (pp.4–2, 5–1).

[5] The set of ''major stationary sources'' potentially subject to BART are listed in CAA section 169A(g)(7).

also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides equal or greater reasonable progress towards improving visibility than BART.

On July 6, 2005, EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at Appendix Y to 40 CFR part 51 (hereinafter referred to as the "BART Guidelines") to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. The BART Guidelines require states to use the approach set forth in the BART Guidelines in making a BART applicability determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts. The BART Guidelines encourage, but do not require states to follow the BART Guidelines in making BART determinations for other types of sources.

The BART Guidelines recommend that states address all visibility impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are sulfur dioxide (SO_2), nitrogen oxides (NO_X), and PM. The BART Guidelines direct states to use their best judgment in determining whether volatile organic compounds (VOCs), or ammonia (NH_3) and ammonia compounds impair visibility in Class I areas.

In their SIPs, states must identify potential BART sources, described as "BART-eligible sources" in the RHR, and document their BART control determination analyses. In making BART determinations, section 169A(g)(2) of the CAA requires that states consider the following factors: (1) The costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. States are free to determine the weight and significance to be assigned to each factor. (70 FR 39170, (July 6, 2005)).

A regional haze SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of EPA approval of the regional haze SIP, as required in the Act (section 169A(g)(4)) and in the RHR (40 CFR 51.308(e)(1)(iv)). In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source. States have the flexibility to choose the type of control measures they will use to meet the requirements of BART.

E. Long-Term Strategy (LTS)

Consistent with the requirement in section 169A(b) of the Act that states include in their regional haze SIP a 10 to 15 year strategy for making reasonable progress, section 51.308(d)(3) of the RHR requires that states include a Long-Term Strategy (LTS) in their SIPs. The LTS is the compilation of all control measures a state will use to meet any applicable RPGs. The LTS must include "enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals" for all Class I areas within, or affected by emissions from, the state. (40 CFR 51.308(d)(3)).

When a state's emissions are reasonably anticipated to cause or contribute to visibility impairment in a Class I area located in another state, the RHR requires the impacted state to coordinate with the contributing states in order to develop coordinated emissions management strategies. (40 CFR 51.308(d)(3)(i)). In such cases, the contributing state must demonstrate that it has included in its SIP all measures necessary to obtain its share of the emission reductions needed to meet the RPGs for the Class I area. The RPOs have provided forums for significant interstate consultation, but additional consultations between states may be required to sufficiently address interstate visibility issues. This is especially true where two states belong to different RPOs.

States should consider all types of anthropogenic sources of visibility impairment in developing their LTS, including stationary, minor, mobile, and area sources. At a minimum, states must describe how each of the seven factors listed below is taken into account in developing their LTS: (1) Emission reductions due to ongoing air pollution control programs, including measures to address Reasonably Attributable Visibility Impairment (RAVI); (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the RPG; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. (40 CFR 51.308(d)(3)(v)).

F. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment (RAVI)

As part of the RHR, EPA revised 40 CFR 51.306(c) regarding the LTS for RAVI to require that the RAVI plan must provide for a periodic review and SIP revision not less frequently than every three years until the date of submission of the state's first plan addressing regional haze visibility impairment, which was due December 17, 2007, in accordance with 51.308(b) and (c). On or before this date, the state must revise its plan to provide for review and revision of a coordinated LTS for addressing reasonably attributable and regional haze visibility impairment, and the state must submit the first such coordinated LTS with its first regional haze SIP revision. Future coordinated LTS's, and periodic progress reports evaluating progress towards RPGs, must be submitted consistent with the schedule for SIP submission and periodic progress reports set forth in 40 CFR 51.308(f) and 51.308(g), respectively. The periodic reviews of a state's LTS must report on both regional haze and RAVI impairment and must be submitted to EPA as a SIP revision, in accordance with 51.308.

G. Monitoring Strategy and Other Implementation Plan Requirements

Section 51.308(d)(4) of the RHR includes the requirement for a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the state. The strategy must be coordinated with the monitoring strategy required in section 51.305 for RAVI. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environment (IMPROVE) network. The monitoring strategy is due with the first regional haze SIP, and it must be reviewed every five years.

H. Consultation With States and Federal Land Managers (FLMs)

The RHR requires that states consult with FLMs before adopting and submitting their SIPs. (40 CFR 51.308(i)). States must provide FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the SIP. This consultation must include the opportunity for the FLMs to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the RPGs and on the development and implementation of strategies to address visibility impairment. Further, a state must include in its SIP a description of how it addressed any comments provided by the FLMs. Finally, a SIP must provide procedures for continuing consultation between the state and FLMs regarding the state's visibility protection program, including development and review of SIP revisions, five-year progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas.

IV. What is EPA's analysis of New Jersey's regional haze submittal?

On July 28, 2009 the State of New Jersey submitted a revision to the New Jersey SIP to address regional haze in the State's Class I Brigantine Wilderness Area as required by EPA's RHR.

A. Affected Class I Areas

New Jersey contains a Class I area, the Brigantine National Wildlife Refuge, where visual impairment that the FLMs have identified as an important value that must be addressed in regional haze plans. Emissions from New Jersey also influence the amount of visibility impairment of Class I areas located in Maine, New Hampshire, and Vermont. New Jersey's Regional Haze SIP will help to improve visibility in these states. Thus, New Jersey is responsible for developing a Regional Haze SIP that addresses its own and other Class I areas, that describes its long-term emission strategy, its role in the consultation processes, and how its SIP meets the other requirements in EPA's regional haze regulations. Because New Jersey is home to a Class I area, New Jersey has the additional responsibility to address the following Regional Haze SIP elements: (a) Calculation of baseline and natural visibility conditions, (b) establishment of RPGs, (c) monitoring requirements, and (d) RAVI requirements as required by EPA's RHR.

B. Long-Term Strategy/Strategies (LTS)

As described above, the Long Term Strategy (LTS) is a compilation of state-specific control measures relied on by the state to obtain its share of emission reductions to support the RPGs for the Brigantine National Wildlife Refuge. New Jersey's LTS for the first implementation period, addresses the emissions reductions from Federal, state, and local controls that take effect in the State from the baseline period starting in 2002 until 2018. New Jersey participated in the MANE–VU RPO regional strategy development process. As a participant, New Jersey supported a regional approach towards deciding which control measures to pursue for regional haze, which was based on technical analyses documented in the following reports: (a) Contributions to Regional Haze in the Northeast and Mid-Atlantic United States [6]; (b) Assessment of Reasonable Progress for Regional Haze in MANE–VU Class I Areas [7]; (c) Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conducting BART Determinations [8]; and (d) Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper, and Pulp Facilities.[9]

The LTS was developed by New Jersey, in coordination with MANE–VU, identifying the emissions units within New Jersey that likely have the largest impacts currently on visibility at the Brigantine National Wildlife Refuge Class I area, estimating emissions reductions for 2018, based on all controls required under Federal and state regulations for the 2002–2018 period (including BART), and comparing projected visibility improvement with the uniform rate of progress for the Brigantine National Wildlife Refuge Class I area.

New Jersey's LTS includes measures needed to achieve its share of emissions reductions and includes enforceable emissions limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals established for the Brigantine National Wildlife Refuge Class I area.

[6] NESCAUM Report at *http://www.nescaum.org/documents/contributions-to-regional-haze-in-the-northeast-and-mid-atlantic—united-states/.*

[7] MANE–VU Report at *http://www.otcair.org/manevu/Document.asp?fview=Reports.*

[8] NESCAUM Report at *http://www.nescaum.org/documents/bart-final-memo-06-28-07.pdf/.*

[9] NESCAUM Report at *http://www.nescaum.org/documents/bart-control-assessment.pdf/.*

1. Emissions Inventory for 2018 With Federal and State Control Requirements

The emissions inventory used in the regional haze technical analyses was developed by the Mid-Atlantic Regional Air Management Association for MANE–VU with assistance from New Jersey. The 2018 emissions inventory was developed by projecting 2002 emissions, and assuming emissions growth due to projected increases in economic activity as well as applying reductions expected from Federal and state regulations affecting the emissions of VOC and the visibility-impairing pollutants NO_X, PM_{10}, $PM_{2.5}$, and SO_2. The BART guidelines direct states to exercise judgment in deciding whether VOC and NH_3 impair visibility in their Class I area(s). As discussed further below, MANE–VU demonstrated that anthropogenic emissions of sulfates are the major contributor to $PM_{2.5}$ mass and visibility impairment at Class I areas in the Northeast and Mid-Atlantic region. It was also determined that the total ammonia emissions in the MANE–VU region are extremely small. In addition, since VOC emissions are aggressively controlled through the New Jersey ozone SIP, the pollutants New Jersey considered under BART are NO_X, PM_{10}, $PM_{2.5}$, and SO_2.

In developing the 2018 reasonable progress goal, and the 2018 projection inventory, New Jersey relied primarily upon the information and analyses developed by MANE–VU to meet the requirements of EPA's regional haze rules. Based on information from the contribution assessment and additional emission inventory analyses, MANE–VU identified the following source categories for further examination for reasonable measures:

- Coal and oil-fired EGUs;
- Point and area source industrial, commercial and institutional (ICI) boilers;
- Cement and Lime Kilns;
- Heating oil; and
- Residential wood combustion.

MANE–VU, for its member states and tribes, analyzed these potential source categories based on the four factors listed in section 169A(g)(1) of the Act and in Section III.C of this action. New Jersey and the MANE–VU states agreed with the analysis that determined that reasonable controls existed for coal and oil-fired EGUs, industrial, commercial and institutional (ICI) boilers and that reducing the sulfur content of heating oil was a reasonable strategy. Additionally, MANE–VU determined that due to the lack of specific data for the wide range of residential wood boilers, it was not reasonable to set particular reductions amounts for emissions from residential wood boilers.

New Jersey adopted controls on EGUs and boilers. While New Jersey's plan does not include emission reduction regulations for residential wood boilers, New Jersey will consider state specific wood burning provisions, which was the strategy agreed to by the MANE–VU states. ICI boiler controls were implemented as an Ozone Transport Commission (OTC) regional measure for VOC and NO_X controls that have benefits for reducing regional haze. New Jersey does not have any cement or lime kilns. More details on the adopted controls are described later in this section.

After identifying potential control measures and performing the four factor analysis, MANE–VU performed initial modeling that showed the visibility impacts from the implementation of the measures. The initial modeling results showed that the projected 2018 visibility on the 20% worst days at the Brigantine Wilderness area was at least as good at the uniform rate of progress. Details of MANE–VU's initial modeling were later documented in the MANE–VU Modeling for RPGs report.[10] Based on the modeling results and other analysis performed by MANE–VU, the MANE–VU states developed ''Asks,'' which are ''emission management'' strategies. These strategies served as the basis for the consultation with the other states.

As part of the modeling needed to assess the emission reductions needed to meet the RPG, MANE–VU developed emissions inventories for four inventory source classifications: (1) Stationary point sources, (2) area sources, (3) off-road mobile sources, and (4) on-road mobile sources. The New York State Department of Environmental Conservation also developed an inventory of biogenic emissions for the entire MANE–VU region. Stationary point emission sources are those sources that emit greater than a specified tonnage per year, depending on the pollutant, with data provided at the facility level. Area source emissions are from stationary sources whose individual emissions are relatively small, but due to the large number of these sources, the collective emissions from the source category could be significant. Off-road mobile source emissions are from equipment that can move but do not use the roadways. On-road mobile source emissions are from automobiles, trucks, and motorcycles that use the roadway system. The emissions from these sources are estimated by vehicle type and road type. Biogenic sources emissions are from natural sources like trees, crops, grasses, and natural decay of plants. Stationary point sources emission data is tracked at the facility level. For all other source types emissions are summed on the county level.

There are many Federal and state control programs being implemented that MANE–VU and New Jersey anticipate will reduce emissions between the baseline period and 2018. Emission reductions from these control programs were projected to achieve substantial visibility improvement by 2018 in the Brigantine National Wildlife Refuge. To assess emissions reductions from ongoing air pollution control programs, BART, and reasonable progress goals; MANE–VU developed 2018 emissions projections called Best and Final. The emissions inventory provided in the Best and Final 2018 projections is based on adopted and enforceable requirements, as well as Federal programs, such as Federal motor vehicle control programs and maximum achievable control technologies (MACT).

These measures are included in the MANE–VU modeling used to determine the amount of progress in the improvement of visibility in Class I areas. MANE–VU States agreed to implement several measures at the state level. These measures are: a timely implementation of BART requirements, 90 percent or more reduction in sulfur dioxide at 167 stacks identified by MANE–VU (or comparable alternative measures), and low sulfur fuel oil regulations (with limits specified for each state).

Controls from various Federal MACT regulations were also utilized in the development of the 2018 emission inventory projections. These MACTs include the industrial boiler/process heater MACT, the combustion turbine and reciprocating internal combustion engines MACTs, and the VOC 2-, 4-, 7-, and 10-year MACT standards.

EPA's industrial boiler/process heater MACT was vacated on June 8, 2007.[11] The MANE–VU States, including the State of New Jersey, included these controls in modeling for their regional haze SIPs. EPA accepts these emission reductions in the modeling for the following reasons. EPA expects to propose a new Industrial Boiler MACT rule to address the vacatur in October 2011 and issue a final rule in April 2012, giving New Jersey time to assure the required controls are in place prior to the end of the first planning period in 2018. In the absence of an established MACT for boilers and process heaters, the statutory language in section 112(j) of the Act specifies a schedule for the incorporation of enforceable MACT-equivalent limits into the Title V operating permits of affected sources. Should circumstances warrant the need to enact section 112(j) of the Act for industrial boilers, compliance with case-by-case MACT limits for industrial boilers would occur no later than January 2015, which is well before the 2018 RPGs for regional haze. The RHR also requires that any resulting differences between emissions projections and actual emissions reductions that may occur will be addressed during the five-year review prior to the next regional haze SIP. In addition, the expected reductions due to the original, vacated Industrial Boiler MACT rule were relatively small compared to the State's projected total SO_2 emissions in 2018 (*i.e.*, one to two percent of the projected 2018 SO_X, $PM_{2.5}$ and coarse particulate matter (PM_{10}) inventory), and are not likely to affect any of New Jersey's modeling conclusions. Thus, even if there is a need to address discrepancies between the projected emissions reductions from the now vacated Industrial Boiler MACT and actual reductions achieved by the replacement MACT, we do not expect that this would be significant enough to affect the adequacy of the New Jersey Regional Haze SIP.

The MANE–VU States' goal was to reduce SO_2 emissions from the largest emission units in the eastern United States by 90 percent or if it was infeasible to achieve that level of reduction, an alternative had to be identified that could include other point sources. In New Jersey, there are four of the 167 units identified by MANE–VU as having the highest SO_2 emissions in the eastern United States. New Jersey has reduced emissions from these four units at each facility by more than 90 percent, thus meeting and exceeding this portion of the reasonable progress goals.

New Jersey is fulfilling its goal of achieving the emission reductions needed to meet its contribution to the reasonable progress goals projected by the MANE–VU modeling with the following measures: BART controls on all BART-eligible facilities, 90 percent or more control at the four New Jersey units from the 167 EGU units identified by MANE–VU, reductions due to New Jersey's Mercury rule, adoption of performance standards at all coal-fired boilers in New Jersey, adoption of the

[10] MANE–VU Modeling for Reasonable Progress Goals. February 7, 2008.

[11] *See NRDC* v. *EPA,* 489 F.3d 1250 (D.C. Cir. 2007).

lower limits on fuel oil and the measures listed in Table 1 developed for other programs that support regional haze emission reduction goals.

TABLE 1—ADDITIONAL STATE CONTROL MEASURES THAT SUPPORT REGIONAL HAZE GOALS

Control measures	Status	Notes
Diesel Idling Rule Changes	Rule adopted May 25, 2007	Direct $PM_{2.5}$ and NO_X reductions.
High Electrical Demand Day units	Rule adopted March 20, 2009	SO_2 and NO_X reductions.
Oil and gas Fired Electric Generating Units (EGUs)	Rule adopted March 20, 2009	NO_X reductions.
Sewage Sludge Incinerators	Rule adopted March 20, 2009	NO_X reductions.
Case by Case NO_X Emission Limit Determinations (FSELs/AELs).	Rule adopted March 20, 2009	NO_X reductions.
Glass Manufacturing	Rule adopted March 20, 2009	NO_X reductions but most benefits will occur post-2010.
Municipal Waste Combustor (Incinerator) NO_X Rule	Rule adopted March 20, 2009	NO_X reductions.
Asphalt Production Plants	Rule adopted March 20, 2009	NO_X reductions.
Diesel Smoke (I/M Cutpoint) Rule Changes	Rule adopted April 3, 2009	$PM_{2.5}$ and NO_X reductions.
Onroad New Jersey Low Emission Vehicle (LEV) Program	Adopted November 28, 2005	VOC, NO_X, SO_2, and direct $PM_{2.5}$ reductions.
Energy Master Plan	Finalized October 22, 2008.	

Federal measures and other control programs relied upon by New Jersey include EPA's NO_X SIP Call; measures adopted for New Jersey's 1-hour and 8-hour ozone attainment demonstration SIPs, Federal 2007 heavy duty diesel engine standards for on-road trucks and busses; Federal Tier 2 tailpipe controls for on-road vehicles; Federal large spark ignition and recreational vehicle controls; and EPA's non-road diesel rules. New Jersey also relied on emission reductions from various Federal MACTs that were vacated, but, as described above, EPA expects these rules to be adopted by 2018, and should not negatively affect New Jersey's fulfillment of its commitment to meet the RPGs. In addition, the RHR requires that any resulting differences between emissions projections and actual emissions reductions that may occur will be addressed during the five-year review prior to the next 2018 Regional Haze SIP.

Tables 2 and 3 are summaries of the 2002 baseline and 2018 estimated emissions inventories for New Jersey. The 2018 estimated emissions include emission growth as well as emission reductions due to ongoing emission control strategies to meet RPGs and BART.

These emissions were used in the modeling that demonstrated that the Brigantine Wildlife Refuge Class I area would meet the Reasonable Progress Goal set for 2018. New Jersey adopted the emission reduction programs that are forecast to improve visibility to meet the goal for 2018, thus New Jersey is projected to achieve its goal for the first implementation period.

TABLE 2—NEW JERSEY/MANE–VU MODELING INVENTORY SUMMARY, 2002 BASE INVENTORY

	NO_X	VOC	CO	NH_3	Primary PM_{10}	Primary $PM_{2.5}$	SO_2
Point	51,593	16,547	12,301	0	6,072	4,779	61,217
Area	26,692	167,883	97,657	17,572	31,664	17,044	10,744
Non-Road	63,479	83,919	704,396	43	5,501	4,997	15,686
On-Road	161,289	110,529	1,461,653	7,316	3,785	2,529	3,627
Total	303,053	378,877	2,276,006	24,931	47,021	29,350	91,273

TABLE 3—NEW JERSEY/MANE–VU MODELING INVENTORY SUMMARY, 2018 PROJECTION INVENTORY

	NO_X	VOC	CO	NH_3	Primary PM_{10}	Primary $PM_{2.5}$	SO_2
Point	31,100	20,267	19,855	564	8,969	7,745	23,421
Area	21,684	134,089	83,119	21,435	31,874	15,220	1,781
Non-Road	41,166	53,625	831,880	52	3,489	3,143	832
On-Road	30,150	31,415	742,000	8,555	1,232	1,140	785
Total	124,100	239,396	1,676,854	30,606	45,564	27,247	26,819

2. Modeling To Support the LTS and Determine Visibility Improvement for Uniform Rate of Progress

MANE–VU performed modeling for the regional haze LTS for the states, the District of Columbia and tribal nations located in Mid-Atlantic and Northeast portions of the United States. The modeling analysis is a complex technical evaluation that began with selection of the modeling system. MANE–VU used a modeling system described below and discussed in more detail in the TSD.

The EPA's Models-3/Community Multiscale Air Quality (CMAQ) version 4.5.1 is a photochemical grid model capable of addressing ozone, PM, visibility and acid deposition on a regional scale. CMAQ modeling of regional haze in the MANE–VU region for 2002 and 2018 was carried out on a grid of 12x12 kilometer (km) cells that covers the 11 MANE–VU States and the District of Columbia and states adjacent to them. This grid is nested within a larger national CMAQ modeling grid of 36x36 km grid cells that covers the continental United States, portions of Canada and Mexico, and portions of the Atlantic and Pacific Oceans along the east and west coasts. Selection of a representative period of meteorology is crucial for evaluating baseline air quality conditions and projecting future changes in air quality due to changes in emissions of visibility-impairing pollutants. MANE–VU conducted an in-depth analysis that resulted in the selection of the entire year of 2002 (January 1–December 31) as the best period of meteorology available for conducting the CMAQ modeling. The MANE–VU States' modeling was developed consistent with EPA guidance.[12]

MANE–VU examined the model performance of the regional modeling for the areas of interest before determining whether the CMAQ model results were suitable for use in the regional haze assessment of the LTS and for use in the modeling assessment. The modeling assessment predicts future levels of emissions and visibility impairment used to support the LTS and to compare predicted, modeled visibility levels with those on the uniform rate of progress. In keeping with the objective of the CMAQ modeling platform, the air quality model performance was evaluated using graphical and statistical assessments based on measured ozone, fine particles, and acid deposition from various monitoring networks and databases for the 2002 base year. MANE–VU used a diverse set of statistical parameters from the EPA's Modeling Guidance to stress and examine the model and modeling inputs. Once MANE–VU determined the model performance to be acceptable, MANE–VU used the model to assess the 2018 RPGs using the current and future year air quality modeling predictions, and compared the RPGs to the uniform rate of progress.

In accordance with 40 CFR 51.308(d)(3), New Jersey provided the supporting documentation for all required analyses used to determine the State's LTS. The technical analyses and modeling used to develop the glide path and to support the LTS are consistent with EPA's RHR, and interim and final EPA Modeling Guidance. EPA accepts the MANE–VU technical modeling to support the LTS and determine visibility improvement for the uniform rate of progress because the modeling system was chosen and used in accordance with EPA Modeling Guidance. EPA agrees with the MANE–VU model performance procedures and results, and that the CMAQ is an appropriate tool for the regional haze assessments for the New Jersey LTS and Regional Haze SIP.

3. Relative Contributions of Pollutants to Visibility Impairment

An important step toward identifying reasonable progress measures is to identify the key pollutants contributing to visibility impairment at each Class I area. To understand the relative benefit of further reducing emissions from different pollutants, MANE–VU developed emission sensitivity model runs using CMAQ to evaluate visibility and air quality impacts from various groups of emissions and pollutant scenarios in the Class I areas on the 20 percent worst visibility days.

MANE–VU's contribution assessment demonstrated that sulfate is the major contributor to $PM_{2.5}$ mass and visibility impairment at Class I areas in the Northeast and Mid-Atlantic Region. Sulfate particles commonly account for more than 50 percent of particle-related light extinction at northeastern Class I areas on the clearest days and for as much as or more than 80 percent on the haziest days. In particular, for the Brigantine National Wildlife Refuge Class I area, on the 20 percent worst visibility days in 2000–2004, sulfate accounted for 66 percent of the particles responsible for light extinction. After sulfate, organic carbon (OC) consistently accounts for the next largest fraction of light extinction due to particles. Organic carbon accounted for 13 percent of light extinction on the 20 percent worst visibility days for Brigantine, followed by nitrate that accounts for 9 percent of light extinction.

The emissions sensitivity analyses conducted by MANE–VU predict that reductions in SO_2 emissions from EGU and non-EGU industrial point sources will result in the greatest improvements in visibility in the Class I areas in the MANE–VU region, more than any other visibility-impairing pollutant. As a result of the dominant role of sulfate in the formation of regional haze in the Northeast and Mid-Atlantic Region, MANE–VU concluded that an effective emissions management approach should rely heavily on broad-based regional SO_2 control efforts in the eastern United States. EPA proposes to accept this conclusion as a reasonable strategy in the eastern United States where reductions in SO_2 emissions will result in the greatest improvements in visibility.

4. Reasonable Progress Goals

New Jersey contains a Class I area, the Brigantine National Wildlife Refuge Class I area, located on the New Jersey shoreline, north of Atlantic City. The RHR at 40 CFR 51.308(d)(1) requires states to establish RPGs for each Class I area within the state (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility. MANE–VU calculated the RPG for the Class I areas in the MANE–VU states, and the CMAQ projections of the effect of emission reductions on visibility in the target year at the end of the first period, 2018, as shown in Table 4.

TABLE 4—REASONABLE PROGRESS GOALS AND PROJECTED FUTURE VISIBILITY FOR THE BRIGANTINE WILDERNESS AREA, DEVELOPED BY MANE–VU

	Baseline visibility (2000–2004)	Natural background conditions for 2064	Reasonable progress goal for 2018	2018 CMAQ projections
20% Worst Days	29.0	12.2	25.1	25.1
20% Best Days	14.3	5.5	14.3	12.2

(All values expressed as deciviews—lower deciviews means better visibility.)

[12] EPA's *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze*, located at *http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf*, (EPA–454/B–07–002), April 2007, and *EPA document, Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations,* located at *http://www.epa.gov/ttnchie1/eidocs/eiguid/index.html*, EPA–454/R–05–001, August 2005, updated November 2005 (''EPA's Modeling Guidance'').

From the MANE–VU analysis, New Jersey determined that if the MANE–VU states adopted certain measures, and states in the surrounding regions adopted similar measures, the Class I areas would meet the RPG for the first progress period ending in 2018. These measures for the MANE–VU states are: Implementation of BART requirements, a 90 percent reduction in SO_2 emissions from 167 EGU emission points (or equivalent emission reduction) and a low sulfur fuel oil strategy. New Jersey adopted regulations sufficient to meet its contribution to the reduction of emissions needed to provide reasonable progress towards achieving natural visibility: A 90 percent or greater reduction in SO_2 emissions from each of the four EGU stacks located in New Jersey, adoption of a low sulfur fuel oil strategy, implementation of BART requirements during the first progress period, as well as continued evaluation of other control measures to reduce SO_2 and NO_X emissions.

The MANE–VU states' goal was to reduce SO_2 emissions from the highest emission stacks in the eastern United States by 90 percent or, if it was infeasible to achieve that level of reduction, an alternative had to be identified that could include other point sources. In New Jersey, there are four of the 167 units identified by MANE–VU as having the highest emissions in the eastern United States. New Jersey has reduced emissions from these sources at each facility by more than 90 percent, thus meeting this portion of the reasonable progress measures.

The modeling predicted that these emission control regulations would result in better visibility which would meet the 25.1 deciviews goal of reasonable progress by 2018 for the Brigantine Class I area. At the time of MANE–VU modeling, some of the other states with sources potentially impacting visibility, in the Class I areas in both New Jersey and the rest of the MANE–VU domain, had not yet made final control determinations for BART, and thus, these controls are not included in the modeling prepared by MANE–VU and used by New Jersey. At that time, not all of the emission reductions from New Jersey's BART-eligible sources were included in the modeling. Any controls resulting from those determinations will provide additional emissions reductions and resulting visibility improvement, which give further assurances that New Jersey accomplished its share of emission reductions needed to RPGs at all Class I areas affected by New Jersey's emissions. This modeling demonstrates that the 2018 base control scenario provides for an improvement in visibility equal to the uniform rate of progress for the Brigantine area Class I areas for the most impaired days over the period of the implementation plan and ensures no degradation in visibility for the least impaired days over the same period.

The modeling supporting the analysis of these RPGs is consistent with EPA guidance prior to the CAIR remand. The regional haze provisions specify that a state may not adopt a RPG that represents less visibility improvement than is expected to result from other CAA requirements during the implementation period. 40 CFR 51.308(d)(1)(vi). Therefore, the CAIR states with Class I areas, like New Jersey, took into account emission reductions anticipated from CAIR in determining their 2018 RPGs. MANE–VU approximated the impact of CAIR by reducing emissions from 167 EGUs by ninety percent. But this reduction was larger, in total tons of emissions reduced, than the reductions expected from CAIR, so MANE–VU added emissions across the modeling domain to more closely approximate the emission reductions from CAIR. This way, MANE–VU States would not overestimate the RPG in case states used the CAIR program as their response to MANE–VU's ''ask'' of ninety percent reductions from the 167 EGUs in the eastern United States.

As discussed in Section I of this action, EPA anticipates that the CSAPR will result in similar or better improvements in visibility than those predicted from CAIR. Because the CSAPR was recently finalized, EPA does not know at this time how it will affect any individual Class I area and cannot accurately model future conditions based on its implementation. However, by the time New Jersey is required to undertake its five year progress review, it is likely that the impact of the CSAPR's contribution to visibility impairment in Class I areas in New Jersey and other states will be meaningfully assessed. Since New Jersey implemented greater than ninety percent control at each of its EGUs that would have been subject to CAIR, which would exceed the emission reductions in New Jersey under CAIR or the CSAPR, it is likely that New Jersey will have contributed its share of reductions that were modeled to produce the RPG at New Jersey's Class I area and other Class I areas impacted by New Jersey. If, for a particular Class I areas, these reductions do not provide similar or greater benefits than CAIR and meeting the RPGs at one of its Class I areas is in jeopardy, the State will be required to address this circumstance in its five year review.

The RPG for the Class I area in New Jersey (and other states' Class I areas affected by New Jersey) are based on modeled projections of future conditions that were developed using the best available information at the time the analysis was completed. While MANE–VU's emission inventory used for modeling included estimates of future emission growth, projections can change as additional information regarding future conditions becomes available. It would be both impractical and resource-intensive to require a state to continually adjust the RPG every time an event affecting these future projections changed. At the same time, EPA established a requirement for a five-year, midcourse review and, if necessary, correction of the states' regional haze plans. See 40 CFR 52.308(g). New Jersey commits to the midcourse review and submitting revisions to the regional haze plan where necessary.

Altogether, these emission controls—a 90 percent reduction in SO2 emissions from EGUs, emission reductions from boilers and a low sulfur fuel oil strategy—are reasonable measures for the reduction strategy required by EPA's RHR. EPA agrees that, combined with New Jersey's BART program, these reductions will provide the emission reductions New Jersey needs to meet its share of the improvements in visibility needed to meet the RPG goal for Brigantine and to assist visibility improvement at other Class I areas affected by New Jersey's emissions.

In order to address a timely implementation of BART, as described in Section IV.B.6. of this action, New Jersey established BART emissions limits for three facilities: PSEG Hudson Generating Station, Chevron Products and ConocoPhillips Bayway Refinery. For two other facilities, Amerada Hess Port Reading Refinery and Sunoco Eagle Point, New Jersey's analyses determined that their emissions were lower than the 250 tons per year threshold to make them eligible for emission reductions under BART. The BART limitations are already in effect for the BART-affected sources, except for additional controls for nitrogen oxides at the PSEG Hudson Generating Station, which will become effective no later than May 1, 2015. New Jersey is revising the permits for these sources to include the modifications needed to meet the BART requirements.

In summary, New Jersey used the MANE–VU analysis which defined the reasonable progress goals, and reasonable measures. The reasonable measures analyses, considered the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts, and the remaining useful life of the existing sources subject to such requirements.

Using input from the MANE–VU consultations, the benefits from the implementation of the identified measures were modeled to project the 2018 visibility levels. These projections serve as the 2018 Reasonable Progress Goal. For the Brigantine Wilderness Area, the 2018 projection is 25.1 deciviews. This projection meets the Uniform Rate of Progress goal developed per EPA's RHR.

Accordingly, EPA proposes to approve New Jersey's RPG for the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge, and proposes that New Jersey's emission reductions will provide its share of the reductions needed to achieve the RPG at Brigantine, as well as other Class I areas in the Northeast United States. Letters from states with Class I areas affected by New Jersey's emissions did not ask for any additional controls beyond those specified in the MANE–VU analyses.

5. Subchapter 9—Sulfur In Fuels

On September 20, 2010, New Jersey satisfied a commitment included in the Regional Haze SIP by adopting revisions to New Jersey Subchapter 9 which implements reductions in the sulfur content of fuel oil, which will aid in reducing sulfates that cause decreased visibility. This regulation will implement low sulfur fuel oil provisions that will reduce the amount of sulfur in fuel oils that are stored, offered for sale, sold, or exchanged in trade for use in New Jersey. On December 9, 2010, New Jersey submitted Subchapter 9 to EPA as a revision to its SIP. New Jersey completed all the administrative requirements for this rule, including a public hearing and response to comments.

The sulfur in fuel limits in New Jersey's rule are the same as the levels of control included in the MANE–VU analysis of reasonable controls for the haze SIP. MANE–VU included these controls in the modeling that showed that the Brigantine area would achieve the reasonable progress goals.

The regulation will reduce the sulfur content in all distillate heating oil (No. 2 and lighter) to 500 parts per million (ppm) by June 1, 2014 and to 15 ppm by July 1, 2016. New Jersey's rule also reduces the sulfur content for No. 4 fuel oil to 2,500 ppm and No. 5, No. 6, and heavier fuel oils to 5,000 ppm for Zones 1, 2, 3 and 5 and 3,000 ppm for Zones 4 and 6 by July 1, 2014. By removing the sulfur in the fuel oils, sulfur oxide emissions and particulate emissions will be reduced which will benefit both the Regional Haze SIP and the attainment of the PM 2.5 national ambient air quality standard. Subchapter 9 has been included in New Jersey's PM 2.5 SIP revision.

Subchapter 9 also contains maximum allowable sulfur dioxide emission limits, expressed in pounds per million BTU, for those sources that chose to control their emissions with control devices. The compliance dates for these limits are the same as for the fuel oil compliance dates. Subchapter 9 provides provisions for the optional use of an alternative emission control plan based on a mathematical combination that must first be approved by New Jersey. These provisions require that for each 24-hour period emissions will not exceed the quantity of sulfur dioxide expressed in pounds per million BTU gross heat input as set forth in Subchapter 9's Tables 2A and 2B. Additional requirements must be satisfied including performing an air quality modeling analysis to insure that the national ambient air quality standards will not be exceeded. These provisions are designed to insure that the use of optional alternative emission controls plans will result in same or greater emission reductions.

New Jersey completed all the administrative requirements for this rule, including a public hearing and addressed the public comments. Since New Jersey's sulfur in fuel rule meets the sulfur limits in the MANE–VU ''ask,'' and meets administrative requirements, EPA proposes to approve New Jersey's Subchapter 9, for use in both the Regional Haze SIP and the PM 2.5 SIP.

6. BART

BART is an element of New Jersey's LTS, as well as a requirement to evaluate controls for older sources that affect Class I areas. The BART regional haze requirement consists of three steps: (a) Identification of all the BART eligible sources; (b) an assessment of whether the BART eligible sources are subject to BART; and (c) the determination of the BART controls.

a. BART-Eligible Sources in New Jersey

The first component of a BART evaluation is to identify all the BART eligible sources. The sources in Table 5 were identified by New Jersey in its July 2009 Regional Haze SIP and met the following criteria to be classified as BART eligible:

- One or more emissions units at the facility are within one of the 26 categories listed in the BART Guidelines (70 FR 39158–39159);
- The emission unit(s) was in existence on August 7, 1977 and begun operation after August 6, 1962;
- Potential emissions of SO_2, NO_X, and PM_{10} from subject units are 250 tons or more per year.

These criteria are from section 169A(b)(2)(A) of the Act, codified in 40 CFR Part 51, Appendix Y.

TABLE 5—BART-ELIGIBLE FACILITIES IDENTIFIED BY THE STATE OF NEW JERSEY

Source	Pollutants	Location (county)	Facility I.D.
PSEG—Hudson	NO_X, SO_2, PM	Hudson	12202
Chevron	NO_X, SO_2, PM	Middlesex	18058
Amerada Hess	NO_X, SO_2	Middlesex	17996
ConocoPhillips	NO_X, PM, SO_2	Union	41805
Sunoco Eagle Point	NO_X, PM, SO_2	Gloucester	55781

The BART Guidelines recommend addressing SO_2, NO_X, and PM_{10} as visibility-impairment pollutants. The Guidelines note that states can decide whether to evaluate VOC or ammonia emissions. New Jersey did not develop additional strategies for VOC or ammonia emissions in its SIP. EPA proposes to agree with New Jersey's determination because of the lack of tools available to estimate emissions and subsequently model VOC and ammonia effects on visibility, and because New Jersey is aggressively addressing VOCs through its approved ozone SIPs. In summary, EPA agrees with New Jersey's determination that SO_2, NO_X, PM_{10}, and $PM_{2.5}$ are the pollutants reasonably anticipated to contribute to visibility impairment to target under BART.

The second component of the BART evaluation is to identify those BART eligible sources that may reasonably be anticipated to cause or contribute to visibility impairment at any Class I area. As discussed in the BART guidelines, a state may choose to consider all BART eligible sources to be subject to BART (70 FR 39.161). The MANE–VU Board decided in June 2004 that because of the collective importance of BART sources, BART determinations should be made by the MANE–VU states for each BART eligible source. New Jersey followed this approach by identifying each of its BART eligible sources as subject to BART, (see Table 5 above), but found upon further review, that emissions from Amerada Hess and Sunoco Eagle Point made them ineligible for BART controls. In its March 2011 supplement to the RH SIP, New Jersey determined that for Amerada Hess and Sunoco Eagle Point, the permitted emissions for these BART-eligible facilities were less than the 250 tons per year threshold for each of the pollutants regulated under the Regional Haze regulations (see section 169A(g)(7) of the Act). Therefore, New Jersey concluded they were not eligible for BART controls.

b. Identification and Evaluation of Additional BART-Eligible Sources in New Jersey

During EPA's review of New Jersey's July 2009 and March 2011 Regional Haze SIP, EPA discovered that two other facilities within the State had units that were BART eligible. These two facilities were not originally identified by New Jersey as BART eligible because the facilities indicated to the state that they planned to shut down. Later the facilities withdrew their requests.

The first BART eligible source, Unit 10 at Vineland Municipal Electric Utility's Howard M. Down Station is under a Federal consent decree [13] to either install additional pollution control measures or to permanently shut down by September 1, 2012. On July 1, 2011, Vineland's Director submitted written certification to EPA and New Jersey that Unit 10 will be retired from service by September 1, 2012. Vineland is required to submit an application to modify its permit by July 30, 2011 and New Jersey will need to submit this element of the permit to EPA as a supplement to the RH SIP by November 2011. Another Vineland source is a distillate fuel oil-fired emergency generator that is considered BART, but EPA agrees that it does not need additional controls because its emissions are small and the unit has not operated for at least 10 years.

The second BART eligible facility is the BL England Generating Station owned by RC Cape May Holding. This facility has three electric generating units that are BART eligible—Units 1, 2 and 3—as well as three support units including a coal handling system that supports the two coal-fired boilers, Units 1 and 2; a natural draft cooling tower that supports the oil fired boiler, Unit 3; and an emergency fire water diesel engine. Units 1 and 2 are subject to an amended Administrative Consent Order (ACO) by New Jersey that requires the units either to repower by December 15, 2011 or meet performance standards by a date certain. Under the ACO, Unit 1 is to add SCR controls for NO_X, a scrubber for SO_2 controls and upgrade the electrostatic precipitator to meet the new performance standards by December 15, 2013. EPA considers that by December 2013, if Unit 1 modifies to meet performance standards, it will be implementing maximum control measures for limiting emissions of NO_X, SO_2 and PM, which meets EPA's BART requirements. Unit 2 is subject to an amended ACO with New Jersey to install selective catalytic reduction (SCR) by May 1, 2012 to reduce emissions of NO_X. Unit 2 currently implements controls for limiting SO_2 emissions with wet scrubbers and PM emissions with electrostatic precipitators (ESP). EPA considers that, if the Unit 2 implements these NO_X controls by May 12, 2012, Unit 2 will be implementing maximum control measures for limiting emissions of NO_X, SO_2 and PM, and will meet EPA's BART requirements. Unit 3 combusts No. 6 Fuel Oil and primarily operates during the summer season on days when the demand for electricity is high. Since 2008, the annual operating capacity has averaged about 3% and has not been more than 32% since 1999. This unit implements SNCR controls for NO_X and is required to comply with a NO_X emission limit of 2.0 lb/MW-hr (equivalent to about 0.20 lb/MM BTU) by May 1, 2015. In addition, to control SO_2 emission, this unit must combust fuel oil with a sulfur limit of 0.50% by July 1, 2014. EPA considers that, by May 15, 2015, Unit 3 will be implementing maximum controls for limiting emissions of NO_X, SO_2 and PM and will meet EPA's BART requirements. For the three remaining support systems (coal handling system, cooling tower, and the emergency diesel engine. EPA considers the existing operations to be BART. In addition, RC Cape May, has indicated it is evaluating the conversion of all three electric steam generating units to natural gas or No. 2 fuel oil. To the extent that RC Cape May decides to convert one or all of the units, New Jersey anticipates that RC Cape May would submit a specific proposal that addresses applicable requirements including BART. For additional details the reader is referred to the TSD.

c. BART Evaluations for Sources Identified as BART by New Jersey

The final component of a BART evaluation is making BART determinations for all BART subject sources. In making BART determinations, section 169A(g)(2) of the Act requires that states consider the following factors: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology. However, a source that implements the maximum feasible level of control for its emissions has met the BART requirements, and no further analysis is needed. Conversely, a source that limits its emissions via an enforceable permit limit no longer needs to be subject to BART review.

NJDEP properly determined that Chevron Products, ConocoPhillips Bayway Refinery, and PSEG Hudson Generating Station are subject to BART review. Chevron Products is reducing its annual combustion limit to bring the facility's potential to emit NO_X to less than 250 tons per year (tpy) by March 15, 2011, so no pollutants exceed the BART threshold and Chevron Products will not be subject to further BART analyses. The ConocoPhillips Bayway Refinery has NO_X, SO_2, and PM controls, emission limits, averaging times, and compliance dates in a Federally enforceable consent decree with New Jersey and EPA. Also, the consent decree requires all the BART-qualified process heaters at the Bayway facility to eliminate oil burning, and to only burn refinery fuel gas with hydrogen sulfide (H_2S) content less than 162 ppmvd in compliance with NSPS subpart J. New Jersey expects full implementation by June 30, 2011. EPA proposes approval of these BART evaluations since they were based on maximum feasible controls or a multi-factor analysis.

PSEG Hudson Generating Station has two boilers serving electric generating units (E1 and E2) and two coal handling systems (E22 and E23) that are subject to BART review. One boiler is coal-fired

[13] U.S. District Court in New Jersey, Civil Action 1:11–cv–1826(RMB–JS), see paragraph 14.

(E2) and subject to controls and Federally enforceable emission limits effective December 31, 2010, due to a Federally enforceable consent decree. The other boiler (E1) primarily combusts natural gas but is also permitted to burn No. 6 fuel oil.

At PSEG, the coal receiving system (E22) and the coal reclaim system (E23) are support systems to coal-fired boiler E2 with the potential to emit particulate emissions only. The conveying systems are covered and the coal piles are controlled with a water dust suppression system. New Jersey determined that the new selective catalytic reduction (SCR) and existing low NO_X burners (LNBs), new flue gas desulfurization (FGD), and new bag house air pollution control systems for oxides of nitrogen (NO_X), sulfur dioxide (SO_2) and particulate matter (PM), respectively, for coal-fired boiler E2, and the existing PM controls for the two coal handling systems, are BART. In addition PSEG has submitted an application to modify the Hudson operating permit to include the following more stringent NO_X emission limits: 1.0 lb/MW-hr when burning natural gas and 2.0 lb/MW-hr when burning No. 6 fuel oil, with a compliance date of May 1, 2015, to coincide with the requirements of the revised NO_X rule at N.J.A.C. 7:27–19.4 Table 3 for E1; and to only burn No. 6 fuel oil, already restricted to 0.3% sulfur by weight, in this boiler when natural gas is curtailed, effective upon approval of the permit modification but no later than December 31, 2011.

New Jersey's BART requirements must be included as operating permit conditions in accordance with 40 CFR part 70, and the State regulations promulgated at N.J.A.C. 7:27–22. Chevron, PSEG Hudson, and ConocoPhillips have submitted timely permit modification applications to incorporate the BART requirements. New Jersey has approved the permit modifications for Chevron and PSEG Hudson and has proposed the permit modifications for ConocoPhillips. When all permit modifications are completed, New Jersey will submit all of the BART determinations and associated documents and permits to EPA as source-specific SIP revisions.

EPA has reviewed New Jersey's BART determinations for all of the BART eligible sources, including all supporting documentation, information and proposed permit modifications. New Jersey has requested public comment on the proposed permit modifications, which identify the required BART controls, and the comment periods have closed. New Jersey is in the process of addressing any comments received and issuing the permit modifications in final form. EPA proposes to approve New Jersey's BART determinations, including the source-specific permit modifications as proposed by New Jersey.

This proposed approval is being proposed under a procedure called parallel processing, whereby EPA proposes rulemaking action concurrently with the state's procedures for amending its regulations or in this instance amending source specific operating permits. If the proposed operating permit revisions are substantially changed in areas other than those identified in this document, EPA will evaluate those changes and may publish another notice of proposed rulemaking. If no substantial changes are made other than those areas cited in this document, EPA will publish a final rulemaking on the revisions. The final rulemaking action by EPA will occur only after the SIP revision has been adopted by New Jersey and submitted formally to EPA for incorporation into the SIP.

EPA proposes to approve New Jersey's BART requirements based on the BART determinations discussed above and the respective BART limitations on emissions, source operation and fuel use. New Jersey's BART determinations contain the appropriate regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the sources. Lastly, New Jersey's BART determinations require BART controls be installed and in operation as expeditiously as practicable, but no later than five years after the date of EPA approval of the Regional Haze SIP, as required in the CAA and in the RHR.

C. Consultation With States and Federal Land Managers

On May 10, 2006, the MANE–VU State Air Directors adopted the Inter-RPO State/Tribal and FLM Consultation Framework that documented the consultation process within the context of regional haze planning, intended to create greater certainty and understanding among RPOs. MANE–VU States held ten consultation meetings and/or conference calls from March 1, 2007 through March 21, 2008. In addition to MANE–VU members attending these meetings and conference calls, participants from VISTAS, Midwest RPO, and the relevant Federal Land Managers also attended. In addition to the conference calls and meeting, the FLMs were given the opportunity to review and comment on each of the technical documents developed by MANE–VU. No additional measures beyond those developed as part of the MANE–VU "ask" were recommended by other states or the FLMs.

New Jersey consulted with the FLMs at a meeting that EPA Region 2 attended on October 20, 2009 during the development of the Regional Haze SIP. New Jersey submitted the draft plan for review by the FLMs for the required ninety-day review period before New Jersey submitted the Regional Haze SIP to EPA and responded to their comments in their response to comments document in Appendix O–3 in the Haze SIP. These actions fulfill EPA's requirements in 40 CFR 51.308(i).

A public hearing on this proposed SIP revision was held on October 27, 2008 at the New Jersey Department of Environmental Protection Public Hearing Room, Trenton, New Jersey. Written comments relevant to the proposal were accepted through November 28, 2008. The only comments were submitted by USEPA, the Fish and Wildlife Service and one of the potential BART sources. New Jersey responded to the comments, as listed in Appendix O–3 of New Jersey's Regional Haze Plan. New Jersey commits in its SIP to ongoing consultation with the FLMs on regional haze issues throughout the implementation of the Regional Haze SIP as required in 40 CFR 51.308(i)(4).

D. Periodic SIP Revisions and Five-Year Progress Reports

New Jersey commits to revise and submit a regional haze implementation plan by July 31, 2018 to address the next ten years of progress toward the national goal in the Act of eliminating manmade haze by 2064, and to submit a plan every ten years thereafter, in accordance with the requirements listed in 40 CFR 51.308(f) of the Federal rule for regional haze. To meet this commitment, New Jersey expects to rely on the collaborative regional organization efforts such as MANE–VU. New Jersey commits to address the following in its Mid-Course Review report: Address any uncertainties encountered during regional haze planning process; report on the progress of the BART analysis, determinations, and implementation; report on the progress of the Low Sulfur Fuel Strategy; report on whether additional potential actions identified in its plan will be implemented and the status of those efforts. The reasonable progress report will evaluate the progress made towards the RPGs for the Brigantine National Wildlife Refuge Class I area, located in New Jersey.

E. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment (RAVI) LTS

In its Regional Haze Plan, New Jersey committed to review the impact of proposed sources on visibility under 40 CFR 52.26 and 52.28, by implementing the Prevention of Significant Deterioration (PSD) permit requirements for new or modified major sources of air pollutants located within 100 kilometers of the Class I area, or within a larger radius on a case-by-case basis, in accordance with all applicable Federal rules for review of the impacts on Class I areas. New Jersey's PSD program prevents new and modified sources from significantly impacting visibility. The PSD program includes a requirement that evaluates the new source's visibility impact on any nearby Class I areas (Brigantine in New Jersey's case).

On June 27, 2011, as part of its acceptance of the PSD delegation from EPA, New Jersey reaffirmed its commitment to notify the Federal Land Manager of new sources that may impact the Class I area, in accordance with 40 CFR 52.21(p).

F. Monitoring Strategy and Other Implementation Plan Requirements

The primary monitoring network for regional haze in New Jersey is the Interagency Monitoring of Protected Visual Environment (IMPROVE) network. There is currently one IMPROVE site in New Jersey, in the Brigantine Wilderness Area of the Edwin B. Forsythe National Wildlife Refuge. IMPROVE monitoring data from 2000–2004 serves as the baseline for the regional haze program, and is relied upon in the July 28, 2009 regional haze submittal. Data produced by the IMPROVE monitoring network are essential for the verification of the effects of changes in emissions on visibility in Class I areas and will be needed for preparing the 5-year progress reports and the 10-year SIP revisions, each of which relies on analysis of the preceding five years of data. In addition, New Jersey operates a comprehensive $PM_{2.5}$ network of filter-based Federal reference method monitors, continuous mass monitors, filter based speciated monitors and the continuous speciated monitors.

New Jersey will continue to operate and maintain the monitoring site at the Brigantine Wilderness Area. EPA will continue its discussions with New Jersey during the course of periodic network reviews on the location of the monitors and the number of monitors in its monitoring network.

New Jersey committed to continuing to submit periodic emission inventories, a mid-course review and a revised plan for the next ten-year period starting in 2018.

V. What action is EPA proposing to take?

EPA is proposing to approve a revision to New Jersey's State Implementation Plan submitted on July 28, 2009, that addressed progress toward reducing regional haze for the first implementation period ending in 2018. The submittal was augmented by submittals on December 9, 2010 with New Jersey's adopted regulation lowering the sulfur content in fuel and on March 2, 2011 which included BART determinations and controls. EPA is proposing to determine that New Jersey's Regional Haze SIP contains the emission reductions needed to achieve New Jersey's share of emission reductions that were determined to be reasonable through the regional planning process. Furthermore, New Jersey's Regional Haze Plan ensures that emissions from the State will not interfere with the reasonable progress goals for neighboring States' Class I areas. Thus, EPA is proposing that the Regional Haze Plan submitted by New Jersey satisfies the requirements of the CAA. EPA is taking this action pursuant to those provisions of the Act. EPA is soliciting public comments on the issues discussed in this document and will consider these comments before taking final action.

In addition, EPA is proposing to approve New Jersey's Subchapter 9, Sulfur in Fuel rule, which is one of the measures needed to fulfill New Jersey's Reasonable Progress Plan.

This proposed approval is being proposed under a procedure called parallel processing, whereby EPA proposes rulemaking action concurrently with the state's procedures for amending its regulations or in this instance amending source specific operating permits to incorporate BART. If the proposed operating permit revisions are substantially changed in areas other than those identified in this action, EPA will evaluate those changes and may publish another notice of proposed rulemaking. If no substantial changes are made other than those areas cited in this action, EPA will publish a final rulemaking on the revisions. The final rulemaking action by EPA will occur only after the SIP revision has been adopted by New Jersey and submitted formally to EPA for incorporation into the SIP.

VI. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this proposed action:

- Is not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this proposed rule approving New Jersey's Regional Haze Plan does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP does not apply to Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: August 2, 2011.

Judith A. Enck,

Regional Administrator, Region 2.

[FR Doc. 2011–20482 Filed 8–10–11; 8:45 am]

BILLING CODE 6560–50–P

Notices

Federal Register

Vol. 76, No. 155

Thursday, August 11, 2011

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. APHIS–2011–0013]

Notice of Decision To Authorize the Importation of Fresh Papaya Fruit From Malaysia into the Continental United States

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Notice.

SUMMARY: We are advising the public of our decision to authorize the importation into the continental United States of fresh papaya fruit from Malaysia. Based on the findings of a pest risk analysis, which we made available to the public for review and comment through a previous notice, we believe that the application of one or more designated phytosanitary measures will be sufficient to mitigate the risks of introducing or disseminating plant pests or noxious weeds via the importation of fresh papaya fruit from Malaysia.

DATES: *Effective Date:* August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Mr. Phillip B. Grove, Regulatory Coordinator, Regulatory Coordination and Compliance, PPQ, APHIS, 4700 River Road Unit 156, Riverdale, MD 20737; (301) 734–6280.

SUPPLEMENTARY INFORMATION:

Background

Under the regulations in ''Subpart—Fruits and Vegetables'' (7 CFR 319.56–1 through 319.56–51, referred to below as the regulations), the Animal and Plant Health Inspection Service (APHIS) of the U.S. Department of Agriculture prohibits or restricts the importation of fruits and vegetables into the United States from certain parts of the world to prevent plant pests from being introduced into and spreading within the United States. Under that process, APHIS may publish a notice in the **Federal Register** announcing the availability of a pest risk analysis that evaluates the risks associated with the importation of a particular fruit or vegetable. Following the close of the 60-day comment period, APHIS may authorize the importation of the fruit or vegetable subject to the risk-mitigation measures identified in the pest risk analysis if: (1) No comments were received on the pest risk analysis; (2) the comments on the pest risk analysis revealed that no changes to the pest risk analysis were necessary; or (3) changes to the pest risk analysis were made in response to public comments, but the changes did not affect the overall conclusions of the analysis and the Administrator's determination of risk.

In accordance with that process, we published a notice [1] in the **Federal Register** on March 15, 2011 (76 FR 13972, Docket No. APHIS–2011–0013), in which we announced the availability, for review and comment, of a pest risk analysis evaluating the risks associated with the importation into the continental United States of fresh papaya fruit (*Carica papaya*) from Malaysia. The pest risk analysis consisted of a pest list identifying pests of quarantine significance that are present in Malaysia and could follow the pathway of importation of papaya into the United States and a risk management document (RMD) identifying phytosanitary measures to be applied to Malaysian papaya to mitigate the pest risk. We solicited comments on the notice for 60 days ending on May 16, 2011. We received one comment by that date, from a State Department of Agriculture. The commenter requested that shipments of papaya not be allowed entry into the commenter's State until the effectiveness of the phytosanitary measures listed in the pest risk analysis had been demonstrated through use on products imported into lower-risk States.

We have determined, for the reasons described in the RMD that accompanied the March 2011 notice, that the measures specified in the RMD will effectively mitigate the risk associated with the importation of fresh papaya fruit from Malaysia. The commenter did not provide any evidence suggesting that the mitigations are not effective. Therefore, we are not taking the action requested by the commenter.

Therefore, in accordance with the regulations in § 319.56–4(c)(2)(ii), we are announcing our decision to authorize the importation into the continental United States of fresh papaya fruit from Malaysia subject to the following phytosanitary measures:

- The fruit must be imported into the United States as a commercial consignment.
- The fruit must be irradiated in accordance with the requirements of 7 CFR part 305 with a minimum absorbed dose of 400 Gy.
- If irradiation is applied outside the United States, each consignment of fruit must be precleared by APHIS inspectors in Malaysia. Each shipment must be inspected jointly by APHIS and Malaysian inspectors and accompanied by a phytosanitary certificate issued by the national plant protection organization (NPPO) of Malaysia certifying that the fruit received the required irradiation treatment.
- If irradiation is to be applied upon arrival in the United States, each consignment of fruit must be inspected by Malaysian inspectors prior to departure and accompanied by a phytosanitary certificate issued by the NPPO of Malaysia.
- Each consignment is subject to inspection at the U.S. port of entry.

These conditions will be listed in the Fruits and Vegetables Import Requirements database (available at *http://www.aphis.usda.gov/favir*). In addition to these specific measures, fresh papaya fruit from Malaysia will be subject to the general requirements listed in § 319.56–3 that are applicable to the importation of all fruits and vegetables. Further, for fruits and vegetables requiring treatment as a condition of entry, the phytosanitary treatment regulations in 7 CFR part 305 contain administrative and procedural requirements that must be observed in connection with the application and certification of specific treatments.

Authority: 7 U.S.C. 450, 7701–7772, and 7781–7786; 21 U.S.C. 136 and 136a; 7 CFR 2.22, 2.80, and 371.3.

[1] To view the notice and the pest risk analysis, go to *http://www.regulations.gov/#!docketDetail;D=APHIS-2011-0013.*

Done in Washington, DC, this 5th day of August 2011.

Gregory L. Parham,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2011–20411 Filed 8–10–11; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. APHIS–2010–0023]

Notice of Availability of a Pest Risk Analysis for the Importation of Fresh Cape Gooseberry Fruit With Husks From Chile

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Notice.

SUMMARY: We are advising the public that we have prepared a pest risk analysis that evaluates the risks associated with the importation into the continental United States of fresh Cape gooseberry fruit (*Physalis peruviana* L.) with husks from Chile. Based on this analysis, we concluded that the application of one or more designated phytosanitary measures will be sufficient to mitigate the risks of introducing or disseminating plant pests or noxious weeds via the importation of fresh Cape gooseberry fruit from Chile. We are making the pest risk analysis available to the public for review and comment.

DATES: We will consider all comments that we receive on or before October 11, 2011.

ADDRESSES: You may submit comments by either of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov/#!documentDetail;D=APHIS-2010-0023-0001.*
- *Postal Mail/Commercial Delivery:* Send your comment to Docket No. APHIS–2010–0023, Regulatory Analysis and Development, PPD, APHIS, Station 3A–03.8, 4700 River Road, Unit 118, Riverdale, MD 20737–1238.

Supporting documents and any comments we receive on this docket may be viewed at *http://www.regulations.gov/#!docketDetail;D=APHIS-2010-0023* or in our reading room, which is located in room 1141 of the USDA South Building, 14th Street and Independence Avenue SW., Washington, DC. Normal reading room hours are 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. To be sure someone is there to help you, please call (202) 690–2817 before coming.

FOR FURTHER INFORMATION CONTACT: Ms. Claudia Ferguson, Regulatory Policy Specialist, Regulations, Permits, and Manuals, PPQ, APHIS, 4700 River Road Unit 133, Riverdale, MD 20737–1231, (301) 734–0754.

SUPPLEMENTARY INFORMATION:

Background

Under the regulations in ''Subpart—Fruits and Vegetables'' (7 CFR 319.56–1 through 319.56–51, referred to below as the regulations), the Animal and Plant Health Inspection Service (APHIS) of the U.S. Department of Agriculture prohibits or restricts the importation of fruits and vegetables into the United States from certain parts of the world to prevent plant pests from being introduced into and spread within the United States.

Section 319.56–4 contains a performance-based process for approving the importation of commodities that, based on the findings of a pest-risk analysis, can be safely imported subject to one or more of the designated phytosanitary measures listed in paragraph (b) of that section.

APHIS received a request from the national plant protection organization (NPPO) of the Republic of Chile to allow the importation of fresh Cape gooseberry fruit (*Physalis peruviana* L.), with husks, to be imported from Chile into the continental United States. We have completed a pest risk assessment for this commodity to identify pests of quarantine significance that could follow the pathway of importation into the United States and, based on this list, have prepared a risk management document to identify phytosanitary measures that could be applied to fresh Cape goosberry fruit with husks from Chile to mitigate the pest risk. We have concluded that fresh Cape gooseberry fruit with husks can be safely imported into the continental United States from Chile using one or more of the five designated phytosanitary measures listed in § 319.56–4(b). For Cape gooseberry fruit with husks from Chile, these measures are:

- Cape gooseberry fruit will be subject to inspection upon arrival in the United States.
- Each consignment of Cape gooseberry fruit must be accompanied by a phytosanitary certificate issued by NPPO of Chile stating: ''The Cape gooseberry in the consignment has been inspected and is free of pests.''
- Cape gooseberry fruit must be imported into the United States in commercial consignments only.

Therefore, in accordance with § 319.56–4(c), we are announcing the availability of our pest risk analysis for public review and comment. The pest risk analysis may be viewed on the Regulations.gov Web site or in our reading room (see **ADDRESSES** above for a link to Regulations.gov and information on the location and hours of the reading room). You may request paper copies of the pest risk analysis by calling or writing to the person listed under **FOR FURTHER INFORMATION CONTACT**. Please refer to the subject of the pest risk analysis you wish to review when requesting copies.

After reviewing any comments we receive, we will announce our decision regarding the import status of fresh Cape gooseberry fruit with husks from Chile in a subsequent notice. If the overall conclusions of the analysis and the Administrator's determination of risk remain unchanged following our consideration of the comments, then we will authorize the importation of fresh Cape gooseberry fruit with husks from Chile into the continental United States subject to the requirements specified in the risk management document.

Authority: 7 U.S.C. 450, 7701–7772, and 7781–7786; 21 U.S.C. 136 and 136a; 7 CFR 2.22, 2.80, and 371.3.

Done in Washington, DC, this 5th day of August 2011.

Gregory L. Parham,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2011–20412 Filed 8–10–11; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–588–845, A–580–834, C–580–835, A–583–831]

Continuation of Antidumping and Countervailing Duty Orders: Stainless Steel Sheet and Strip in Coils From Japan, Korea, and Taiwan

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: As a result of the determinations by the Department of Commerce (the ''Department'') that revocation of the antidumping duty (''AD'') orders on stainless steel sheet and strip in coils from Japan, Korea, and Taiwan would likely lead to continuation or recurrence of dumping, that revocation of the countervailing duty (''CVD'') order on stainless steel sheet and strip in coils from Korea would likely lead to continuation or

recurrence of a countervailable subsidy, and the determinations by the International Trade Commission (the ''ITC'') that revocation of these AD and CVD orders would likely lead to a continuation or recurrence of material injury to an industry in the United States, the Department is publishing this notice of the continuation of these AD orders and CVD order.

DATES: *Effective Date:* August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Shawn Thompson (AD orders) or Eric Greynolds (CVD order), AD/CVD Operations, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street & Constitution Avenue NW., Washington, DC 20230; *telephone:* (202) 482–1776 and (202) 482–6071, respectively.

SUPPLEMENTARY INFORMATION:

Background

On June 2, 2010, the Department initiated and the ITC instituted sunset reviews of the AD and CVD orders on stainless steel sheet and strip from Japan, Korea, and Taiwan pursuant to sections 751(c) and 752 of the Tariff Act of 1930, as amended (the ''Act''), respectively. *See Initiation of Five-Year (''Sunset'') Reviews,* 75 FR 30777 (June 2, 2010). As a result of its reviews, the Department found that revocation of the AD orders would likely lead to continuation or recurrence of dumping and that revocation of the CVD order would likely lead to continuation or recurrence of subsidization, and notified the ITC of the margins of dumping and the subsidy rates likely to prevail were the orders revoked. *See Certain Stainless Steel Sheet and Strip in Coils From Germany, Japan, the Republic of Korea, and Taiwan: Final Results of the Expedited Second Sunset Reviews of the Antidumping Duty Orders,* 75 FR 62104 (October 7, 2010), and *Stainless Steel Sheet and Strip in Coils From the Republic of Korea: Final Results of Expedited Second Sunset Review,* 75 FR 62101 (October 7, 2010) (collectively, ''*Final Results''*).

On August 2, 2011, the ITC determined that revocation of the AD and CVD orders on stainless steel sheet and strip in coils from Japan, Korea, and Taiwan would likely lead to continuation or recurrence of material injury within a reasonably foreseeable time. *See Stainless Steel Sheet and Strip from Germany, Italy, Japan, Korea, Mexico, and Taiwan,* 76 FR 46323 (August 2, 2011) (''*ITC Determination''*) and USITC Publication 4244 entitled *Stainless Steel Sheet and Strip from Germany, Italy, Japan, Korea, Mexico, and Taiwan* (Inv. No. 701–TA–382 and 731–TA–798–803 (Second Review)), (July 2011).

Scope of the Orders

The merchandise covered by these AD and CVD orders is stainless steel sheet and strip in coils. Stainless steel is an alloy steel containing, by weight, 1.2 percent or less of carbon and 10.5 percent or more of chromium, with or without other elements. The subject sheet and strip is a flat-rolled product in coils that is greater than 9.5 mm in width and less than 4.75 mm in thickness, and that is annealed or otherwise heat treated and pickled or otherwise descaled. The subject sheet and strip may also be further processed (*e.g.,* cold-rolled, polished, aluminized, coated, *etc.*) provided that it maintains the specific dimensions of sheet and strip following such processing.

The merchandise subject to these orders is classified in the Harmonized Tariff Schedule of the United States (HTSUS) at subheadings: 7219.13.00.31, 7219.13.00.51, 7219.13.00.71, 7219.13.00.81, 7219.14.00.30, 7219.14.00.65, 7219.14.00.90, 7219.32.00.05, 7219.32.00.20, 7219.32.00.25, 7219.32.00.35, 7219.32.00.36, 7219.32.00.38, 7219.32.00.42, 7219.32.00.44, 7219.33.00.05, 7219.33.00.20, 7219.33.00.25, 7219.33.00.35, 7219.33.00.36, 7219.33.00.38, 7219.33.00.42, 7219.33.00.44, 7219.34.00.05, 7219.34.00.20, 7219.34.00.25, 7219.34.00.30, 7219.34.00.35, 7219.35.00.05, 7219.35.00.15, 7219.35.00.30, 7219.35.00.35, 7219.90.00.10, 7219.90.00.20, 7219.90.00.25, 7219.90.00.60, 7219.90.00.80, 7220.12.10.00, 7220.12.50.00, 7220.20.10.10, 7220.20.10.15, 7220.20.10.60, 7220.20.10.80, 7220.20.60.05, 7220.20.60.10, 7220.20.60.15, 7220.20.60.60, 7220.20.60.80, 7220.20.70.05, 7220.20.70.10, 7220.20.70.15, 7220.20.70.60, 7220.20.70.80, 7220.20.80.00, 7220.20.90.30, 7220.20.90.60, 7220.90.00.10, 7220.90.00.15, 7220.90.00.60, and 7220.90.00.80. (Prior to 2001, U.S. imports under HTS statistical reporting numbers 7219.13.00.31, 7219.13.00.51, 7219.13.00.71, 7219.13.00.81 were entered under HTS statistical reporting numbers 7219.13.00.30, 7219.13.00.50, 7219.13.00.70, 7219.13.00.80.) Although the HTSUS subheadings are provided for convenience and customs purposes, the Department's written description of the merchandise subject to these orders is dispositive.

Excluded from the scope of these orders are the following: (1) Sheet and strip that is not annealed or otherwise heat treated and pickled or otherwise descaled, (2) sheet and strip that is cut to length, (3) plate (*i.e.,* flat-rolled stainless steel products of a thickness of 4.75 mm or more), (4) flat wire (*i.e.,* cold-rolled sections, with a prepared edge, rectangular in shape, of a width of not more than 9.5 mm), and (5) razor blade steel, (6) flapper valve steel, (7) suspension foil, (8) certain stainless steel foil for automotive catalytic converters, (9) permanent magnet iron-chromium-cobalt alloy stainless strip, (10) certain electrical resistance ally steel, (11) certain martensitic precipitation-hardenable stainless steel, and (12) three specialty stainless steels typically used in certain industrial blades and surgical and medication instruments. Items 5 through 12 are further described below.

Razor blade steel is a flat-rolled product of stainless steel, not further worked than cold-rolled (cold-reduced), in coils, of a width of not more than 23 mm and a thickness of 0.266 mm or less, containing, by weight, 12.5 to 14.5 percent chromium, and certified at the time of entry to be used in the manufacture of razor blades. *See* Chapter 72 of the HTSUS, ''Additional U.S. Note'' 1(d).

Flapper valve steel is also excluded from the scope. This product is defined as stainless steel strip in coils containing, by weight, between 0.37 and 0.43 percent carbon, between 1.15 and 1.35 percent molybdenum, and between 0.20 and 0.80 percent manganese. This steel also contains, by weight, phosphorus of 0.025 percent or less, silicon of between 0.20 and 0.50 percent, and sulfur of 0.020 percent or less. The product is manufactured by means of vacuum arc remelting, with inclusion controls for sulphide of no more than 0.04 percent and for oxide of no more than 0.05 percent. Flapper valve steel has a tensile strength of between 210 and 300 ksi, yield strength of between 170 and 270 ksi, plus or minus 8 ksi, and a hardness (Hv) of between 460 and 590. Flapper valve steel is most commonly used to produce specialty flapper valves in compressors.

Suspension foil excluded from the scope is a specialty steel product used in the manufacture of suspension assemblies for computer disk drives. Suspension foil is described as 302/304 grade or 202 grade stainless steel of a thickness between 14 and 127 microns, with a thickness tolerance of plus-or-minus 2.01 microns, and surface glossiness of 200 to 700 percent Gs. Suspension foil must be supplied in coil widths of not more than 407 mm, and with a mass of 225 kg or less. Roll marks may only be visible on one side, with no scratches of measurable depth. The material must exhibit residual stresses of 2 mm maximum deflection, and flatness of 1.6 mm over 685 mm length.

Certain stainless steel foil for automotive catalytic converters is also excluded from the scope. This stainless steel strip in coils is a specialty foil with a thickness of between 20 and 110 microns used to produce a metallic substrate with a honeycomb structure for use in automotive catalytic converters. The steel contains, by weight, carbon of no more than 0.030 percent, silicon of no more than 1.0 percent, manganese of no more than 1.0 percent, chromium of between 19 and 22 percent, aluminum of no less than 5.0 percent, phosphorus of no more than 0.045 percent, sulfur of no more than 0.03 percent, lanthanum of less than 0.002 or greater than 0.05 percent, and total rare earth elements of more than 0.06 percent, with the balance iron.

Permanent magnet iron-chromium-cobalt alloy stainless strip is also excluded from the scope. This ductile stainless steel strip contains, by weight, 26 to 30 percent chromium, and 7 to 10 percent cobalt, with the remainder of iron, in widths 228.6 mm or less, and a thickness between 0.127 and 1.270 mm. It exhibits magnetic remanence between 9,000 and 12,000 gauss, and a coercivity of between 50 and 300 oersteds. This product is most commonly used in electronic sensors and is currently available under proprietary trade names such as ''Arnokrome III.'' [1]

Certain electrical resistance alloy steel is also excluded from the scope. This product is defined as a non-magnetic stainless steel manufactured to American Society of Testing and Materials (ASTM) specification B344 and containing, by weight, 36 percent nickel, 18 percent chromium, and 46 percent iron, and is most notable for its resistance to high temperature corrosion. It has a melting point of 1390 degrees Celsius and displays a creep rupture limit of 4 kilograms per square millimeter at 1000 degrees Celsius. This steel is most commonly used in the production of heating ribbons for circuit breakers and industrial furnaces, and in rheostats for railway locomotives. The product is currently available under proprietary trade names such as ''Gilphy 36.'' [2]

Certain martensitic precipitation-hardenable stainless steel is also excluded from the scope. This high-strength, ductile stainless steel product is designated under the Unified Numbering System (UNS) as S45500-grade steel, and contains, by weight, 11 to 13 percent chromium, and 7 to 10 percent nickel. Carbon, manganese, silicon and molybdenum each comprise, by weight, 0.05 percent or less, with phosphorus and sulfur each comprising, by weight, 0.03 percent or less. This steel has copper, niobium, and titanium added to achieve aging, and will exhibit yield strengths as high as 1700 Mpa and ultimate tensile strengths as high as 1750 Mpa after aging, with elongation percentages of 3 percent or less in 50 mm. It is generally provided in thicknesses between 0.635 and 0.787 mm, and in widths of 25.4 mm. This product is most commonly used in the manufacture of television tubes and is currently available under proprietary trade names such as ''Durphynox 17.'' [3]

Three specialty stainless steels typically used in certain industrial blades and surgical and medical instruments are also excluded from the scope. These include stainless steel strip in coils used in the production of textile cutting tools (*e.g.,* carpet knives).[4] This steel is similar to AISI grade 420 but containing, by weight, 0.5 to 0.7 percent of molybdenum. The steel also contains, by weight, carbon of between 1.0 and 1.1 percent, sulfur of 0.020 percent or less, and includes between 0.20 and 0.30 percent copper and between 0.20 and 0.50 percent cobalt. This steel is sold under proprietary names such as ''GIN4 Mo.'' The second excluded stainless steel strip in coils is similar to AISI 420–J2 and contains, by weight, carbon of between 0.62 and 0.70 percent, silicon of between 0.20 and 0.50 percent, manganese of between 0.45 and 0.80 percent, phosphorus of no more than 0.025 percent and sulfur of no more than 0.020 percent. This steel has a carbide density on average of 100 carbide particles per 100 square microns. An example of this product is ''GIN5'' steel. The third specialty steel has a chemical composition similar to AISI 420 F, with carbon of between 0.37 and 0.43 percent, molybdenum of between 1.15 and 1.35 percent, but lower manganese of between 0.20 and 0.80 percent, phosphorus of no more than 0.025 percent, silicon of between 0.20 and 0.50 percent, and sulfur of no more than 0.020 percent. This product is supplied with a hardness of more than Hv 500 guaranteed after customer processing, and is supplied as, for example, ''GIN6''.[5]

In addition, as a result of changed circumstances reviews, the Department has revoked, in part, the Japanese AD order with respect to imports of the following products:

- Stainless steel welding electrode strips that are manufactured in accordance with American Welding Society (AWS) specifications ANSI/AWS A5.9–93 (*see* 65 FR 17856, April 5, 2000);
- Certain stainless steel used for razor blades, medical surgical blades, and industrial blades that are sold under proprietary names such as DSRIK7, DSRIKA, and DSRIK9 (*see* 65 FR 54841, September 11, 2000);
- Certain stainless steel lithographic sheet that is made of 304-grade stainless steel (*see* 65 FR 64423, October 27, 2000); and
- Certain nickel clad stainless steel sheet (*see* 65 FR 77578, December 12, 2000).

Determination

As a result of the determinations by the Department and the ITC that revocation of these AD and CVD orders would likely lead to continuation or recurrence of dumping or a countervailable subsidy, and of material injury to an industry in the United States, pursuant to section 751(d)(2) of the Act, the Department hereby orders the continuation of the AD and CVD orders on stainless steel sheet and strip in coils from Japan, Korea, and Taiwan. U.S. Customs and Border Protection will continue to collect cash deposits at the rates in effect at the time of entry for all imports of subject merchandise. The effective date of the continuation of these orders is the date of publication in the **Federal Register** of this Notice of Continuation.

Pursuant to sections 751(c)(2) and 751(c)(6) of the Act, the Department intends to initiate the next five-year review of these finding/orders not later than July 2016.

These five-year (sunset) reviews and notice are in accordance with section 751(c) of the Act and published pursuant to section 777(i)(1) of the Act.

Dated: August 3, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

[FR Doc. 2011–20436 Filed 8–10–11; 8:45 am]

BILLING CODE 3510–DS–P

[1] ''Arnokrome III'' is a trademark of the Arnold Engineering Company.

[2] ''Gilphy 36'' is a trademark of Imphy, S.A.

[3] ''Durphynox 17'' is a trademark of Imphy, S.A.

[4] This list of uses is illustrative and provided for descriptive purposes only.

[5] ''GIN4 Mo,'' ''GIN5'' and ''GIN6'' are the proprietary grades of Hitachi Metals America, Ltd.

DEPARTMENT OF COMMERCE

International Trade Administration

[A–552–802]

Certain Frozen Warmwater Shrimp From the Socialist Republic of Vietnam: Extension of Time Limit for Final Results of Antidumping Duty Administrative Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (''Department'') is extending the time limit for the final results of the administrative review of certain frozen warmwater shrimp (''shrimp'') from the Socialist Republic of Vietnam (''Vietnam''). The review covers the period February 1, 2009, through January 31, 2010.

DATES: *Effective Date:* August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Susan Pulongbarit, Paul Walker, or Jerry Huang, AD/CVD Operations, Office 9, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; *telephone:* (202) 482–4031, (202) 482–0413, or (202) 482–4047, respectively.

Background

On March 4, 2011, the Department published the preliminary results of the review of shrimp from Vietnam. *See Certain Frozen Warmwater Shrimp From the Socialist Republic of Vietnam: Preliminary Results, Partial Rescission, and Request for Revocation, In Part, of the Fifth Administrative Review,* 76 FR 12054 (March 4, 2011). The final results are currently due no later than August 16, 2011. *See Certain Frozen Warmwater Shrimp from the Socialist Republic of Vietnam: Extension of Final Results of Antidumping Duty Administrative Review,* 76 FR 36519 (June 22, 2011).

Statutory Time Limits

In antidumping duty administrative reviews, section 751(a)(3)(A) of the Tariff Act of 1930, as amended (''the Act''), requires the Department to make a final determination in an administrative review of an antidumping duty order within 120 days after the date on which the preliminary results are published. However, if it is not practicable to complete the review within this time period, section 751(a)(3)(A) of the Act allows the Department to extend the 120-day period to 180 days after the preliminary results if it determines it is not practicable to complete the review within the foregoing time period.

Extension of Time Limit for Final Results of Review

We determine that it is not practicable to complete the final results of this administrative review within the 120-day time limit, as currently extended, because the Department requires additional time to analyze issues in case and rebuttal briefs submitted by parties, including comments on surrogate country selection, the wage rate calculation, and shrimp surrogate value.

Therefore, in accordance with section 751(a)(3)(A) of the Act, the Department is extending the time period for completion of the final results of this review, which is currently due on August 16, 2011, by 15 days to 180 days after the date on which the preliminary results were published. Therefore, the final results are now due no later than August 31, 2011.

We are issuing and publishing this notice in accordance with sections 751(a)(3)(A) and 777(i) of the Act.

Dated: August 5, 2011.

Christian Marsh,

Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. 2011–20435 Filed 8–10–11; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–890]

Wooden Bedroom Furniture From the People's Republic of China: Final Results and Final Rescission in Part

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: On February 10, 2011, the Department of Commerce (Department) published in the *Federal Register* its preliminary results of the administrative review of the antidumping duty order on wooden bedroom furniture (WBF) from the People's Republic of China (PRC), covering the period January 1, 2009 through December 31, 2009.[1] We gave interested parties an opportunity to comment on the *Preliminary Results.* After reviewing the interested parties' comments, we made changes to our calculations for these final results of the review. The final dumping margins for this review are listed in the ''Final Results of the Review'' section below.

DATES: *Effective Date:* August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Jeff Pedersen or Rebecca Pandolph, AD/CVD Operations, Office 4, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; *telephone:* (202) 482–2769 and (202) 482–3627, respectively.

Background

On March 11, 2011, the Department issued a memorandum finding that Dalian Huafeng Furniture Group Co., Ltd. (Huafeng) is the successor-in-interest to Dalian Huafeng Furniture Co., Ltd. for purposes of this proceeding and for the application of the antidumping law.

Between March 14, 2011, and March 22, 2011, Petitioners,[2] Huafeng, Dongguan Great Reputation Furniture Co., Ltd., Home Meridian International, Inc, d/b/a Samuel Lawrence Furniture Co. and Pulaski Furniture Company (Home Meridian), Import Services, Inc., Hooker Furniture Corporation, Nantong Yangzi Furniture Co., Ltd. (Nantong Yangzi), and Dongguan Cambridge Furniture Co., Ltd. and Glory Oceanic Co., Ltd. (collectively Cambridge), Butler Woodcrafters, Inc., Barry Imports East Corp., and Zhangjiagang Zheng Yan Decoration Co., Ltd. (ZYD), submitted case briefs to the Department. On March 24, 2011, the Department rejected a portion of Huafeng's case brief due to the inclusion of untimely new factual information. On March 25, 2011, Huafeng resubmitted its case brief with the new factual information excluded. On March 28, 2011, Petitioners, Huafeng, Home Meridian, Import Services, Inc., Nantong Yangzi, and Cambridge filed rebuttal briefs with the Department.

On March 7, 2011, the Department received surrogate value (SV) information from interested parties and placed SV information for truck freight on the record.[3] On March 17, 2011, Petitioners filed information with the Department which they claimed rebutted, clarified, or corrected SV information placed on the record after the *Preliminary Results* of the review were issued. On March 21, 2011, the

[1] *See Wooden Bedroom Furniture From the People's Republic of China: Preliminary Results of Antidumping Duty Administrative Review and Intent to Rescind Review in Part,* 76 FR 7534 (February 10, 2011) (*Preliminary Results*).

[2] Petitioners are the American Furniture Manufactures Committee for Legal Trade and Vaughan-Bassett Furniture Company, Inc. (Petitioners).

[3] *See* Memorandum to the File regarding ''Antidumping Duty Administrative Review of Wooden Bedroom Furniture from the People's Republic of China,'' dated March 7, 2011.

Department requested that interested parties withhold comments regarding the SV for truck freight from their case briefs because it was considering whether to accept Petitioners' March 17, 2011, rebuttal SV submission. On April 18, 2011, the Department rejected a portion of Petitioners' March 17, 2011, rebuttal SV submission but allowed Petitioners to refile the submission without the rejected information. Petitioners submitted a redacted version of their March 17, 2011, rebuttal SV submission on April 19, 2011. On April 18, 2011, the Department extended the deadline for case and rebuttal briefs regarding the valuation of truck freight until April 21, 2011, and April 25, 2011, respectively. On April 21, 2011, the Department received a case brief regarding truck freight from Petitioners. On April 25, 2011, Huafeng submitted a rebuttal brief regarding truck freight.

On May 20, 2011, the Department issued a memorandum further explaining its decision in the *Preliminary Results* not to extend the time for Petitioners to withdraw their request for a review of ZYD.[4] On May 25, 2011, ZYD commented on this post preliminary memorandum.

On June 10, 2011, the Department extended the time period for completing the final results of the instant administrative review.[5] On July 13, 2011, the Department further extended the time period for completing the final results of the instant administrative review.[6]

Analysis of Comments Received

All issues raised in the case and rebuttal briefs by parties in this review are addressed in the Memorandum from Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, to Ronald K. Lorentzen, Deputy Assistant Secretary for Import Administration, ''Issues and Decision Memorandum for the Final Results of the Administrative Review of the Antidumping Duty Order on Wooden Bedroom Furniture from the People's Republic of China,'' dated July 11, 2011, which is hereby adopted by this notice (Issues and Decision Memorandum). A list of the issues which parties raised and to which we responded in the Issues and Decision Memorandum is attached to this notice as an Appendix. The Issues and Decision Memorandum is a public document and is on file in the Central Records Unit, Main Commerce Building, Room 7046, and is accessible on the Web at *http://ia.ita.doc.gov/frn*>. The paper copy and electronic version of the memorandum are identical in content.

Changes Since the Preliminary Results

Based on an analysis of the comments received, the Department has made the following changes:

Surrogate Values [7]

• We valued Huafeng's plywood inputs based on Philippine imports of HTS subheading 4412.13.10. *See* Comment 7 of the Issues and Decision Memorandum.

• We valued Huafeng's self-adhesive tape inputs based on Philippine imports of HTS subheading 3919.10.90. *See* Comment 8 of the Issues and Decision Memorandum.

• We valued Huafeng's glue consumed as overhead based on Philippine imports of HTS subheading 3506.91. *See* Comment 10 of the Issues and Decision Memorandum.

• We recalculated the surrogate financial ratios using additional financial statements that were provided after the *Preliminary Results* were issued and after changing our treatment of certain financial statement line items. *See* Comment 19 of the Issues and Decision Memorandum.

Ministerial Errors [8]

• We corrected the calculation of indirect selling expenses deducted from U.S. price. *See* Comment 12 of the Issues and Decision Memorandum.

• We corrected our conversion of square meters of oak veneer into cubic decimeters. *See* Comment 13 of the Issues and Decision Memorandum.

• We removed the quantity of electricity consumed by the samples workshop from the quantity of electricity consumption allocated to subject merchandise. *See* Comment 2 of the Issues and Decision Memorandum.

Other Changes [9]

• We calculated the per-unit brokerage and handling SV using a different weight. *See* Comment 6 of the Issues and Decision Memorandum.

• We added the quantity of electricity consumed to the factors of production used in assembling cardboard cartons.

Period of Review

The period of review (POR) is January 1, 2009, through December 31, 2009.

Scope of the Order

The product covered by the order is WBF. WBF is generally, but not exclusively, designed, manufactured, and offered for sale in coordinated groups, or bedrooms, in which all of the individual pieces are of approximately the same style and approximately the same material and/or finish. The subject merchandise is made substantially of wood products, including both solid wood and also engineered wood products made from wood particles, fibers, or other wooden materials such as plywood, strand board, particle board, and fiberboard, with or without wood veneers, wood overlays, or laminates, with or without non-wood components or trim such as metal, marble, leather, glass, plastic, or other resins, and whether or not assembled, completed, or finished.

The subject merchandise includes the following items: (1) Wooden beds such as loft beds, bunk beds, and other beds; (2) wooden headboards for beds (whether stand-alone or attached to side rails), wooden footboards for beds, wooden side rails for beds, and wooden canopies for beds; (3) night tables, night stands, dressers, commodes, bureaus, mule chests, gentlemen's chests, bachelor's chests, lingerie chests, wardrobes, vanities, chessers, chifforobes, and wardrobe-type cabinets; (4) dressers with framed glass mirrors that are attached to, incorporated in, sit on, or hang over the dresser; (5) chests-on-chests,[10] highboys,[11] lowboys,[12] chests of drawers,[13] chests,[14] door

[4] *See* Memorandum from Abdelali Elouaradia, Director, Office 4 to Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations ''Wooden Bedroom Furniture from the People's Republic of China: Untimely Withdrawal of Request for Administrative Review of Zhangjiagang Zheng Yan Decoration Co., Ltd. dated May 20, 2011.

[5] *See Wooden Bedroom Furniture from the People's Republic of China: Extension of the Time Limit for the Final Results of the Antidumping Duty Administrative Review,* 76 FR 34043 (June 10, 2011).

[6] *See Wooden Bedroom Furniture from the People's Republic of China: Extension of the Time Limit for the Final Results of the Antidumping Duty Administrative Review,* 76 FR 41215 (July 13, 2011).

[7] For all changes to SVs, *see* the July 11, 2011 Final Results Surrogate Value Memorandum.

[8] For all corrections to ministerial errors, *see* the July 11, 2011 Final Results Analysis Memorandum.

[9] *See also* the Final Results Analysis Memorandum.

[10] A chest-on-chest is typically a tall chest-of-drawers in two or more sections (or appearing to be in two or more sections), with one or two sections mounted (or appearing to be mounted) on a slightly larger chest; also known as a tallboy.

[11] A highboy is typically a tall chest of drawers usually composed of a base and a top section with drawers, and supported on four legs or a small chest (often 15 inches or more in height).

[12] A lowboy is typically a short chest of drawers, not more than four feet high, normally set on short legs.

[13] A chest of drawers is typically a case containing drawers for storing clothing.

[14] A chest is typically a case piece taller than it is wide featuring a series of drawers and with or

chests,[15] chiffoniers,[16] hutches,[17] and armoires;[18] (6) desks, computer stands, filing cabinets, book cases, or writing tables that are attached to or incorporated in the subject merchandise; and (7) other bedroom furniture consistent with the above list.

The scope of the order excludes the following items: (1) Seats, chairs, benches, couches, sofas, sofa beds, stools, and other seating furniture; (2) mattresses, mattress supports (including box springs), infant cribs, water beds, and futon frames; (3) office furniture, such as desks, stand-up desks, computer cabinets, filing cabinets, credenzas, and bookcases; (4) dining room or kitchen furniture such as dining tables, chairs, servers, sideboards, buffets, corner cabinets, china cabinets, and china hutches; (5) other non-bedroom furniture, such as television cabinets, cocktail tables, end tables, occasional tables, wall systems, book cases, and entertainment systems; (6) bedroom furniture made primarily of wicker, cane, osier, bamboo or rattan; (7) side rails for beds made of metal if sold separately from the headboard and footboard; (8) bedroom furniture in which bentwood parts predominate;[19] (9) jewelry armories;[20] (10) cheval mirrors;[21] (11) certain metal parts;[22] (12) mirrors that do not attach to, incorporate in, sit on, or hang over a dresser if they are not designed and marketed to be sold in conjunction with a dresser as part of a dresser-mirror set; (13) upholstered beds[23] and (14) toy boxes.[24]

Imports of subject merchandise are classified under subheadings 9403.50.9042 and 9403.50.9045[25] of the U.S. Harmonized Tariff Schedule (''HTSUS'') as ''wooden * * * beds'' and under subheading 9403.50.9080 of the HTSUS as ''other * * * wooden furniture of a kind used in the bedroom.'' In addition, wooden headboards for beds, wooden footboards for beds, wooden side rails for beds, and wooden canopies for beds may also be entered under subheading 9403.50.9042 or 9403.50.9045 of the HTSUS as ''parts of wood.'' Subject merchandise may also be entered under subheadings 9403.50.9041 or 9403.60.8081.[26] Further, framed glass mirrors may be entered under subheading 7009.92.1000[27] or 7009.92.5000 of the HTSUS as ''glass mirrors * * * framed.'' The order covers all WBF meeting the above description, regardless of tariff classification. Although the HTSUS subheadings are provided for convenience and customs purposes, our written description of the scope of this proceeding is dispositive.

Separate Rates

Companies Granted Separate Rates in the Preliminary Results

In the *Preliminary Results,* we determined that the following companies demonstrated their eligibility for separate-rate status: (1) Huafeng; (2) Baigou Crafts Factory of Fengkai; (3) Dongguan Bon Ten Furniture Co., Ltd.; (4) Dongguan Kin Feng Furniture Co., Ltd.; (5) Dongguan Singways Furniture Co., Ltd.; (6) Dongguan Sunshine Furniture Co., Ltd.; (7) Hong Kong Da Zhi Furniture Co., Ltd., Dongguan Grand Style Furniture Co., Ltd.; (8) Longkou Huangshan Furniture Factory; (9) Nanhai Baiyi Woodwork Co. Ltd.; (10) Nanjing Nanmu Furniture Co., Ltd.; (11) Season Furniture Manufacturing Co., Season Industrial Development Co.; (12) Shenyang Shining Dongxing Furniture Co., Ltd.; (13) Shenzhen Shen Long Hang Industry Co., Ltd.; (14) Wanhengtong Nueevder (Furniture) Manufacture Co., Ltd., Dongguan Wanengtong Industry Co., Ltd.; (15) Xilinmen Furniture Co., Ltd.; (16) Zhangjiagang Zheng Yan Decoration Co. Ltd., and (17) Zhangjiang Sunwin Arts & Crafts Co., Ltd. For these final results,

without one or more doors for storing clothing. The piece can either include drawers or be designed as a large box incorporating a lid.

[15] A door chest is typically a chest with hinged doors to store clothing, whether or not containing drawers. The piece may also include shelves for televisions and other entertainment electronics.

[16] A chiffonier is typically a tall and narrow chest of drawers normally used for storing undergarments and lingerie, often with mirror(s) attached.

[17] A hutch is typically an open case of furniture with shelves that typically sits on another piece of furniture and provides storage for clothes.

[18] An armoire is typically a tall cabinet or wardrobe (typically 50 inches or taller), with doors, and with one or more drawers (either exterior below or above the doors or interior behind the doors), shelves, and/or garment rods or other apparatus for storing clothes. Bedroom armoires may also be used to hold television receivers and/or other audio-visual entertainment systems.

[19] As used herein, bentwood means solid wood made pliable. Bentwood is wood that is brought to a curved shape by bending it while made pliable with moist heat or other agency and then set by cooling or drying. *See* CBP's Headquarters Ruling Letter 043859, dated May 17, 1976.

[20] Any armoire, cabinet or other accent item for the purpose of storing jewelry, not to exceed 24 inches in width, 18 inches in depth, and 49 inches in height, including a minimum of 5 lined drawers lined with felt or felt-like material, at least one side door (whether or not the door is lined with felt or felt-like material), with necklace hangers, and a flip-top lid with inset mirror. *See* Issues and Decision Memorandum from Laurel LaCivita to Laurie Parkhill, Office Director, concerning ''Jewelry Armoires and Cheval Mirrors in the Antidumping Duty Investigation of Wooden Bedroom Furniture from the People's Republic of China,'' dated August 31, 2004. *See also Wooden Bedroom Furniture From the People's Republic of China: Final Changed Circumstances Review, and Determination To Revoke Order in Part*, 71 FR 38621 (July 7, 2006).

[21] Cheval mirrors are any framed, tiltable mirror with a height in excess of 50 inches that is mounted on a floor-standing, hinged base. Additionally, the scope of the order excludes combination cheval mirror/jewelry cabinets. The excluded merchandise is an integrated piece consisting of a cheval mirror, *i.e.*, a framed tiltable mirror with a height in excess of 50 inches, mounted on a floor-standing, hinged base, the cheval mirror serving as a door to a cabinet back that is integral to the structure of the mirror and which constitutes a jewelry cabinet line with fabric, having necklace and bracelet hooks, mountings for rings and shelves, with or without a working lock and key to secure the contents of the jewelry cabinet back to the cheval mirror, and no drawers anywhere on the integrated piece. The fully assembled piece must be at least 50 inches in height, 14.5 inches in width, and 3 inches in depth. *See Wooden Bedroom Furniture From the People's Republic of China: Final Changed Circumstances Review and Determination To Revoke Order in Part*, 72 FR 948 (January 9, 2007).

[22] Metal furniture parts and unfinished furniture parts made of wood products (as defined above) that are not otherwise specifically named in this scope (*i.e.*, wooden headboards for beds, wooden footboards for beds, wooden side rails for beds, and wooden canopies for beds) and that do not possess the essential character of wooden bedroom furniture in an unassembled, incomplete, or unfinished form. Such parts are usually classified under HTSUS subheadings 9403.90.7005, 9403.90.7010, or 9403.90.7080.

[23] Upholstered beds that are completely upholstered, *i.e.*, containing filling material and completely covered in sewn genuine leather, synthetic leather, or natural or synthetic decorative fabric. To be excluded, the entire bed (headboards, footboards, and side rails) must be upholstered except for bed feet, which may be of wood, metal, or any other material and which are no more than nine inches in height from the floor. *See Wooden Bedroom Furniture from the People's Republic of China: Final Results of Changed Circumstances Review and Determination to Revoke Order in Part*, 72 FR 7013 (February 14, 2007).

[24] To be excluded the toy box must: (1) Be wider than it is tall; (2) have dimensions within 16 inches to 27 inches in height, 15 inches to 18 inches in depth, and 21 inches to 30 inches in width; (3) have a hinged lid that encompasses the entire top of the box; (4) not incorporate any doors or drawers; (5) have slow-closing safety hinges; (6) have air vents; (7) have no locking mechanism; and (8) comply with American Society for Testing and Materials (''ASTM'') standard F963–03. Toy boxes are boxes generally designed for the purpose of storing children's items such as toys, books, and playthings. *See Wooden Bedroom Furniture from the People's Republic of China: Final Results of Changed Circumstances Review and Determination to Revoke Order in Part*, 74 FR 8506 (February 25, 2009). Further, as determined in the scope ruling memorandum ''Wooden Bedroom Furniture from the People's Republic of China: Scope Ruling on a White Toy Box,'' dated July 6, 2009, the dimensional ranges used to identify the toy boxes that are excluded from the wooden bedroom furniture order apply to the box itself rather than the lid.

[25] These HTSUS numbers, as well as the numbers in footnote 20, reflect the HTSUS numbers currently in effect. These numbers differ from those used in the last completed antidumping duty administrative review of WBF from the PRC because the HTSUS has been revised.

[26] These HTSUS numbers were added to the scope in the 2009 Annual New Shipper Review of the proceeding. *See Wooden Bedroom Furniture from the People's Republic of China: Final Results of Antidumping Duty New Shipper Reviews,* 76 FR 9747 (February 22, 2011).

[27] *Id.*

we continue to find that evidence placed on the record of this review demonstrates that these companies provided information that shows both a *de jure* and *de facto* absence of government control with respect to their respective exports of the merchandise under review and, thus, these companies are eligible for separate-rate status.

With respect to the following companies that were not selected for individual examination in this review we continue to find they should be granted a separate rate because they are wholly owned by individuals or companies located in a market economy: (1) Cheng Meng Furniture (PTE) Ltd., Cheng Meng Decoration & Furniture (Suzhou) Co., Ltd.; (2) COE, Ltd; (3) Dongguan Hero Way Woodwork Co., Ltd., Dongguan Da Zhong Woodwork Co., Ltd., Hero Way Enterprises Ltd., Well Earth International Ltd.; (4) Dongguan Liaobushangdun Huada Furniture Factory, Great Rich (HK) Enterprise Co., Ltd.; (5) Eurosa (Kunshan) Co., Ltd., Eurosa Furniture Co., (PTE) Ltd.; (6) Garri Furniture (Dong Guan) Co., Ltd., Molabile International, Inc. Weei Geo Enterprise Co., Ltd.; (7) Hualing Furniture (China) Co., Ltd., Tony House Manufacture (China) Co., Ltd., Buysell Investments Ltd., Tony House Industries Co., Ltd.; (8) Jardine Enterprise, Ltd.; (9) Winny Overseas, Ltd; (10) Meikangchi (Nantong) Furniture Company Ltd.; and (11) Zhong Shan Fullwin Furniture Co., Ltd. As wholly foreign-owned companies, we have no evidence indicating that these companies are under the control of the PRC government. Therefore, a separate-rate analysis is not necessary to determine whether these companies are independent from government control.[28]

Since the *Preliminary Results,* the only comments received regarding our separate rate determinations were from parties noting that the Department failed to mention Dongguan Cambridge Furniture Co., Ltd., Glory Oceanic Co., Ltd. and Dongguan Great Reputation Furniture Co., Ltd. in its preliminary separate rate determination. Parties claimed that the Department apparently overlooked the separate rate submissions by these companies. We agree that in the *Preliminary Results,* we inadvertently omitted Dongguan Cambridge Furniture Co., Ltd., Glory Oceanic Co., Ltd. and Dongguan Great Reputation Furniture Co., Ltd. from the list of companies that had demonstrated their eligibility to receive a separate rate.[29] Therefore, for the final results, we have granted these companies a separate rate.

Companies Not Providing Separate Rate Certifications or Applications

In the *Preliminary Results,* we stated that the following nine companies or company groupings for which the Department initiated the instant review did not provide a separate rate certification or application and therefore have not demonstrated their eligibility for separate rate status in this administrative review:

- Dongguan Creation Furniture Co., Ltd., Creation Industries Co., Ltd.
- Foshan Guanqiu Furniture Co., Ltd.
- Jiangsu Weifu Group Fullhouse Furniture Mfg. Corp.
- Link Silver Ltd. (V.I.B.), Forward Win Enterprises Company Limited, Dongguan Haoshun Furniture Ltd.
- Nantong Yushi Furniture Co., Ltd.
- Shanghai Aosen Furniture Co., Ltd.
- Shenzhen Xiande Furniture Factory
- Tarzan Furniture Industries, Ltd., Samso Industries Ltd.
- Tianjin Master Home Furniture

In the *Preliminary Results,* we also found that (1) Nantong Yangzi, (2) Zhongshan Gainwell Furniture Co., Ltd., and (3) Dongguan Landmark Furniture Products Ltd. shipped subject merchandise during the POR, had not filed separate rate certifications or applications and thus we treated these companies as part of the PRC-wide entity. Since the *Preliminary Results,* aside from Nantong Yangzi,[30] no interested parties submitted comments regarding the companies listed above. In Comment 14 of the accompanying Issues and Decision Memorandum, we addressed Nantong Yangzi's comments and determined not to rescind the review with respect to Nantong Yangzi. Therefore, for the final results, we continue to treat these entities as part of the PRC–Wide entity.

Adverse Facts Available (AFA)

In the *Preliminary Results,* we determined that in accordance with sections 776(a)(2)(A) and (C) and 776(b) of the Act, the use of AFA is appropriate for the PRC-wide entity. The Department assigned a dumping margin of 216.01 percent, the highest rate on the record of any segment of the proceeding to all companies that are part of the PRC-wide entity, as AFA.[31] No interested party commented on this determination regarding the PRC-wide entity and we have made no changes from our *Preliminary Results* with respect to this issue.

Also in the *Preliminary Results,* we determined that Huafeng failed to report certain sales and thus withheld necessary information within the meaning of section 776(a)(2)(A) of the Act and failed to act to the best of its ability to comply with the Department's requests for information within the meaning of section 776(b) of the Act. We therefore applied a dumping margin based on AFA to Huafeng's unreported sales, pursuant to section 776(b) of the Act. As partial AFA, we applied to the unreported sales a margin of 216.01 percent. Parties commented both on our decision to apply AFA and on our choice of the AFA rate applied to Huafeng. After considering these comments, we have continued to apply to Huafeng's unreported sales an AFA margin of 216.01 percent.[32]

Corroboration of Secondary Information

Section 776(c) of the Act provides that, when the Department relies on secondary information rather than on information obtained in the course of an investigation or review, it shall, to the extent practicable, corroborate that information from independent sources that are reasonably at its disposal. Secondary information is defined as information derived from the petition that gave rise to the investigation or review, the final determination concerning the subject merchandise, or any previous review under section 751 of the Act concerning the subject merchandise.[33] To corroborate means that the Department will satisfy itself that the secondary information to be used has probative value.[34] To corroborate secondary information, the Department will, to the extent practicable, examine the reliability and relevance of the information to be used.[35] Independent sources used to

[28] *See Preliminary Results; see also Notice of Final Determination of Sales at Less Than Fair Value: Creatine Monohydrate From the People's Republic of China,* 64 FR 71104–05 (December 20, 1999) (where the Department determined that a respondent that was wholly foreign-owned qualified for a separate rate).

[29] *See* Issues and Decision Memorandum at Comment 15.

[30] *See* Issues and Decision Memorandum at Comment 14.

[31] *See Preliminary Results.*

[32] *See* Issues and Decision Memorandum at Comment 1.

[33] *See* the Statement of Administrative Action accompanying the Uruguay Round Agreements Act, H.R. Doc. 103–316 Vol. 1 at 870 (1994) (*SAA*).

[34] *See Id.*

[35] *See Tapered Roller Bearings and Parts Thereof, Finished and Unfinished From Japan, and Tapered Roller Bearings, Four Inches or Less in Outside Diameter, and Components Thereof, From Japan; Preliminary Results of Antidumping Duty Administrative Reviews and Partial Termination of Administrative Reviews,* 61 FR 57391, 57392

corroborate such information may include, for example, published price lists, official import statistics and customs data, and information obtained from interested parties during the particular investigation or review.[36]

The 216.01 AFA rate that the Department is using in this review is a company-specific rate calculated in the *2004–2005 New Shipper Review* of the WBF order.[37] No additional information has been presented in the current review which calls into question the reliability of this secondary information. Thus, we have determined that this secondary information continues to be reliable. With respect to the relevance aspect of corroboration, the Department will consider information reasonably at its disposal to determine whether a margin continues to have relevance. Where circumstances indicate that the selected margin is not appropriate as AFA, the Department will disregard the margin and determine an appropriate margin.[38] Similarly, the Department does not apply a margin that has been discredited.[39] To assess the relevancy of the rate used, the Department compared the transaction-specific margins calculated for Huafeng in the instant administrative review with the 216.01 percent rate calculated in the *2004–2005 New Shipper Review* and found that the 216.01 percent margin was within the range of the calculated margins on the record of the instant administrative review. Because the dumping margins used to corroborate the AFA rate are not unusually high dumping margins relative to the calculated rates determined for the cooperating respondent, the Department is satisfied that the dumping margins used for corroborative purposes reflect commercial reality because they are based upon real transactions that occurred during the POR and were subject to verification by the Department.[40]

Since the 216.01 percent margin is within the range of transaction-specific margins on the record of this administrative review, the Department has determined that the 216.01 percent margin continues to be relevant for use as an AFA rate for the PRC-wide entity in this administrative review. Also, because this rate is within the range of Huafeng's transaction-specific margins in this review, we find the rate relevant to Huafeng's unreported sales.

As the adverse margin is both reliable and relevant, the Department has determined that it has probative value. Accordingly, the Department has determined that this rate meets the corroboration criterion established in section 776(c) of the Act. Huafeng has raised arguments with respect to the reliability and relevance of this rate, which are addressed in the accompanying Issues and Decision Memorandum at Comment 1.

Final Partial Rescission of Administrative Review

In the *Preliminary Results,* the Department stated its intent to rescind the administrative review with respect to the following companies because they all reported that they made no shipments during the POR.

- Clearwise Company Limited
- Dongguan Huangsheng Furniture Co., Ltd.[41]
- Dongguan Mu Si Furniture Co. Ltd.
- Fleetwood Fine Furniture LP
- Hainan Jong Bao Lumber Co. Ltd/ Jibbon Enterprise Co., Ltd.
- Shanghai Fangjia Industry Co., Ltd.
- Yeh Brothers World Trade Inc.
- Golden Well International (HK) Ltd.
- Zhejiang Tianyi Scientific and Educational Equipment Co., Ltd. (''Zhejiang Tianyi'')[42]

No parties commented on our intent to rescind. Because there is no information or argument on the record of the current review that warrants reconsidering our intent to rescind, we are rescinding this administrative review with respect to the above-listed companies.

Final Results of the Review

We determine that the following weighted-average percentage margins exist for the POR:

Exporter	Antidumping Duty Percent Margin
Dalian Huafeng Furniture Co., Ltd./Dalian Huafeng Furniture Group Co., Ltd	41.75
Baigou Crafts Factory of Fengkai	41.75
Cambridge Furniture Co., Ltd., Glory Oceanic Co., Ltd	41.75
Cheng Meng Furniture (PTE) Ltd., Cheng Meng Decoration & Furniture (Suzhou) Co., Ltd	41.75
COE, Ltd	41.75
Dongguan Bon Ten Furniture Co., Ltd	41.75
Dongguan Great Reputation Furniture Co., Ltd	41.75
Dongguan Hero Way Woodwork Co., Ltd., Dongguan Da Zhong Woodwork Co., Ltd., Hero Way Enterprises Ltd., Well Earth International Ltd	41.75
Dongguan Kin Feng Furniture Co., Ltd	41.75
Dongguan Liaobushangdun Huada Furniture Factory , Great Rich (HK) Enterprise Co., Ltd	41.75
Dongguan Singways Furniture Co., Ltd	41.75

(November 6, 1996) (unchanged in *Tapered Roller Bearings and Parts Thereof, Finished and Unfinished, From Japan, and Tapered Roller Bearings, Four Inches or Less in Outside Diameter, and Components Thereof, From Japan; Final Results of Antidumping Duty Administrative Reviews and Termination in Part,* 62 FR 11825 (March 13, 1997)).

[36] *See* the *SAA* at 870; *see also Notice of Preliminary Determination of Sales at Less Than Fair Value: High and Ultra-High Voltage Ceramic Station Post Insulators from Japan,* 68 FR 35627, 35629 (June 16, 2003) (unchanged in *Notice of Final Determination of Sales at Less Than Fair Value: High and Ultra-High Voltage Ceramic Station Post Insulators from Japan,* 68 FR 62560 (November 5, 2003)).

[37] *See Wooden Bedroom Furniture from the People's Republic of China: Final Results of the 2004–2005 Semi-Annual New Shipper Reviews,* 71 FR 70739, 70741 (December 6, 2006) (*2004–2005 New Shipper Review*).

[38] *See Fresh Cut Flowers From Mexico; Final Results of Antidumping Duty Administrative Review,* 61 FR 6812, 6814 (February 22, 1996) (where the Department disregarded the highest margin in that case as adverse best information available (the predecessor to facts available) because the margin was based on another company's uncharacteristic business expense resulting in an unusually high margin).

[39] *See D&L Supply Co.* v. *United States,* 113 F.3d 1220, 1221 (Fed. Cir. 1997) (ruling that the Department will not use a margin that has been judicially invalidated).

[40] *See* the Corroboration Memorandum dated concurrently with this notice.

[41] Dongguan Huangsheng Furniture Co., Ltd.'s only sales made during the POR were covered by a new shipper review for the period January 1, 2009, through December 31, 2009. The new shipper review of this company was completed and therefore, these shipments are not subject to this administrative review. *See Wooden Bedroom Furniture from the People's Republic of China: Final Results of Antidumping Duty New Shipper Reviews,* 76 FR 9747 (February 22, 2011).

[42] Zhejiang Tianyi's only sales made during the POR were covered by a new shipper review covering the period January 1, 2009, through June 30, 2009 and thus are not subject to this review. *See Wooden Bedroom Furniture from the People's Republic of China: Final Results of Antidumping Duty New Shipper Review,* 75 FR 44764 (July 29, 2010).

Exporter	Antidumping Duty Percent Margin
Dongguan Sunshine Furniture Co., Ltd	41.75
Eurosa (Kunshan) Co., Ltd., Eurosa Furniture Co., (PTE) Ltd (Eurosa)	41.75
Garri Furniture (Dong Guan) Co., Ltd., Molabile International, Inc. Weei Geo Enterprise Co., Ltd	41.75
Hong Kong Da Zhi Furniture Co., Ltd., Dongguan Grand Style Furniture Co., Ltd	41.75
Hualing Furniture (China) Co., Ltd., Tony House Manufacture (China) Co., Ltd., Buysell Investments Ltd., Tony House Industries Co., Ltd	41.75
Jardine Enterprise, Ltd	41.75
Longkou Huangshan Furniture Factory	41.75
Meikangchi (Nantong) Furniture Company Ltd	41.75
Nanhai Baiyi Woodwork Co. Ltd	41.75
Nanjing Nanmu Furniture Co., Ltd	41.75
Season Furniture Manufacturing Co., Season Industrial Development Co	41.75
Shenyang Shining Dongxing Furniture Co., Ltd	41.75
Shenzhen Shen Long Hang Industry Co., Ltd	41.75
Wanhengtong Nueevder (Furniture) Manufacture Co., Ltd., Dongguan Wanengtong Industry Co., Ltd	41.75
Winny Overseas, Ltd	41.75
Xilinmen Furniture Co., Ltd	41.75
Zhangjiagang Zheng Yan Decoration Co. Ltd	41.75
Zhangjiang Sunwin Arts & Crafts Co., Ltd	41.75
Zhong Shan Fullwin Furniture Co., Ltd	41.75
PRC–Wide Entity	216.01

Assessment Rates

The Department will determine, and CBP shall assess, antidumping duties on all appropriate entries of subject merchandise in accordance with the final results of this review. For assessment purposes, we calculated exporter/importer- (or customer) -specific assessment rates for merchandise subject to this review. Where appropriate, we calculated an *ad valorem* rate for each importer (or customer) by dividing the total dumping margins for reviewed sales to that party by the total entered values associated with those transactions. For duty-assessment rates calculated on this basis, we will direct CBP to assess the resulting *ad valorem* rate against the entered customs values for the subject merchandise. Where an importer- (or customer) -specific assessment rate is *de minimis* (*i.e.,* less than 0.50 percent), the Department will instruct CBP to assess that importer's (or customer's) entries of subject merchandise without regard to antidumping duties. We intend to instruct CBP to liquidate entries containing subject merchandise exported by the PRC-wide entity at the PRC-wide rate determined in these final results. The Department intends to issue appropriate assessment instructions directly to CBP 15 days after publication of the final results of this review.

Cash-Deposit Requirements

The following cash deposit requirements will be effective upon publication of the final results of this administrative review for all shipments of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date, as provided for by section 751(a)(2)(C) of the Act: (1) For the exporters listed above, the cash deposit rate will be the rates shown for those companies; (2) for previously investigated or reviewed PRC and non-PRC exporters not listed above that have separate rates, the cash deposit rate will continue to be the exporter-specific rate published for the most recent period; (3) for all PRC exporters of subject merchandise which have not been found to be entitled to a separate rate, the cash deposit rate will be the PRC-wide rate of 216.01 percent; and (4) for all non-PRC exporters of subject merchandise which have not received their own rate, the cash deposit rate will be the rate applicable to the PRC exporters that supplied that non-PRC exporter. These deposit requirements shall remain in effect until further notice.

Notification of Interested Parties

This notice also serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in the Secretary's presumption that reimbursement of the antidumping duties occurred and the subsequent assessment of double antidumping duties.

This notice also serves as a reminder to parties subject to administrative protective order (APO) of their responsibility concerning the return or destruction of proprietary information disclosed under the APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of the return/destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

Disclosure

We will disclose the calculations performed in these final results within five days of the date of public announcement of the final results to parties in this proceeding in accordance with 19 CFR 351.224(b). We are issuing and publishing these final results and notice in accordance with sections 751(a)(1) and 777(i)(1) of the Act.

Dated: August 5, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

Appendix

Comment 1: Unreported Sales
Comment 2: Electricity
Comment 3: Warranty Expenses
Comment 4: Freight Revenue
Comment 5: The Appropriate Methodology for Valuing Cardboard Cartons
Comment 6: Brokerage and Handling
Comment 7: The Appropriate SV for Plywood
Comment 8: The Appropriate SV for Tape
Comment 9: The Appropriate SV for Poly Foam
Comment 10: The Appropriate SV for the Glue Used in Furniture Production
Comment 11: Error in the Draft Rescission Instructions
Comment 12: Calculation Error

Comment 13: The Appropriate Conversion Factor for Oak Veneer
Comment 14: Whether the Department Should Rescind its Administrative Review of Nantong Yangzi Furniture Co., Ltd.
Comment 15: Whether Great Reputation, Cambridge and Glory Are Entitled to a Separate Rate
Comment 16: Combination Rates
Comment 17: Duty Absorption
Comment 18: The Appropriate SV for Labor
Comment 19: Financial Ratios
Comment 20: Whether to use Huafeng's ME Purchases to Value Certain Inputs
Comment 21: Truck Freight
Comment 22: Whether the Department Should Rescind its Administrative Review of Zhangjiagang Zheng Yan Decoration Co., Ltd.

[FR Doc. 2011–20434 Filed 8–10–11; 8:45 am]

BILLING CODE

DEPARTMENT OF COMMERCE

International Trade Administration

[C–570–938]

Citric Acid and Certain Citrate Salts From the People's Republic of China: Partial Rescission of Countervailing Duty Administrative Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

DATES: *Effective Date:* August 11, 2011.

FOR FURTHER INFORMATION CONTACT: Matthew Jordan or Sergio Balbontin at (202) 482–1540 or (202) 482–6478; AD/CVD Operations, Office 1, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230.

Background

On May 2, 2011, the Department of Commerce (''the Department'') published a notice announcing the opportunity to request an administrative review of the countervailing duty order on citric acid and certain citrate salts (''citric acid'') from the People's Republic of China (''PRC''). *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity To Request Administrative Review,* 76 FR 24460 (May 2, 2011). On May 31, 2011, Huangshi Xinghua Biochemical Co., Ltd. (''Xinghua''), a producer and exporter of citric acid, timely requested that the Department conduct an administrative review of the countervailing duty order on citric acid, covering merchandise exported by Xinghua during the period of January 1, 2010, through December 31, 2010. In accordance with 19 CFR 351.221(c)(1)(i), the Department published a notice initiating this administrative review with regard to Xinghua. *See Initiation of Antidumping and Countervailing Duty Administrative Reviews and Request for Revocation in Part,* 76 FR 37781 (June 28, 2011).

Rescission of Review

Pursuant to 19 CFR 351.213(d)(l), the Secretary will rescind an administrative review, in whole or in part, if the party that requested a review withdraws the request within 90 days of the date of publication of the notice of initiation of the requested review. On July 27, 2011, Xinghua withdrew its request for review of itself within the 90-day period. Therefore, in response to Xinghua's timely withdrawal request, and as no other party requested a review of Xinghua, the Department is rescinding this administrative review with respect to Xinghua.

Assessment

The Department will instruct U.S. Customs and Border Protection (''CBP'') to assess countervailing duties on all appropriate entries. For Xinghua, the countervailing duties shall be assessed at rates equal to the cash deposit of estimated countervailing duties required at the time of entry, or withdrawal from warehouse, for consumption, in accordance with 19 CFR 351.212(c)(1)(i). The Department intends to issue appropriate assessment instructions to CBP 15 days after the date of publication of this notice of rescission of administrative review with respect to Xinghua.

Notification Regarding Administrative Protective Order

This notice serves as a final reminder to parties subject to administrative protective order (''APO'') of their responsibility concerning the disposition of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of the return/destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a sanctionable violation.

This notice of rescission is issued and published in accordance with sections 751(a)(l) and 777(i)(l) of the Tariff Act of 1930, as amended, and 19 CFR 351.213(d)(4).

Dated: August 4, 2011.

Christian Marsh,

Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. 2011–20427 Filed 8–10–11; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XA631

Endangered and Threatened Species; Take of Anadromous Fish

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of availability and request for comment.

SUMMARY: Notice is hereby given that NMFS has received two Tribal Resource Management Plans (TRMPs), one from the Shoshone-Bannock Tribes (SBT) and one from the Confederated Tribes of the Umatilla Indian Reservation (CTUIR), and two Fishery Management and Evaluation Plans (FMEPs) from the Oregon Department of Fish and Wildlife (ODFW), for fishery management in the Snake River Basin in Northeast Oregon. The TRMPs are provided pursuant to the Tribal 4(d) Rule; the ODFW FMEPs are submitted for approval under Limit 4 of the 4(d) Rule for Pacific salmon and steelhead. This document serves to notify the public of the availability for comment of the proposed evaluation of the Secretary of Commerce (Secretary) as to how the TRMPs address the criteria in the ESA, and the availability of the state FMEPs for public comment. NMFS also announces the availability of a draft Environmental Assessment (EA) for the pending determinations.

DATES: Comments and other submissions must be received at the appropriate address or fax number (see **ADDRESSES**) no later than 5 p.m. Pacific time on September 12, 2011.

ADDRESSES: Written responses to the application should be sent to Enrique Patiño, National Marine Fisheries Services, Salmon Management Division, 7600 Sand Point Way, NE., Seattle, WA 98115. Comments may also be submitted by e-mail to: *NEOregonFisheryPlans.nwr@noaa.gov.* Include in the subject line of the e-mail comment the following identifier: Comments on Northeast Oregon Fishery Plans. Comments may also be sent via facsimile (fax) to (206) 526–6736. Requests for copies of the permit applications should be directed to the

National Marine Fisheries Services, Salmon Management Division, 7600 Sand Point Way NE., Seattle, WA 98115. The documents are also available on the Internet at *http://www.nwr.noaa.gov.* Comments received will also be available for public inspection, by appointment, during normal business hours by calling (503) 230–5418.

FOR FURTHER INFORMATION CONTACT: Enrique Patiño at (206) 526–4655 or *e-mail: enrique.patino@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Species Covered in This Notice

Chinook salmon (*Oncorhynchus tshawytscha*): Threatened, naturally produced and artificially propagated Snake River Spring/Summer-run.

Steelhead (*O. mykiss*): Threatened, naturally produced and artificially propagated Snake River Basin.

Background

On June 7, 2011, NMFS received a final revised TRMP from the SBT, addressing management of SBT fisheries in the Grande Ronde and Imnaha Rivers. On June 8, 2011, NMFS received a final revised TRMP from the CTUIR, addressing management of CTUIR fisheries in the Grande Ronde and Imnaha Rivers. On June 14, 2011, NMFS received two final revised FMEPs from the ODFW, one describing state-managed recreational fisheries in the Grande Ronde River and one describing state-managed fisheries in the Imnaha River. The FMEPs and TRMPs include adaptive management measures to limit ESA impacts and propose conservative harvest regimes on the affected listed species. The FMEPs and TRMPs describe monitoring programs that would be in place to ensure that the implementation of the fisheries is as intended, and that assumptions regarding the effects of the fisheries, particularly in application of the proposed ESA take limits, continue to remain valid.

The FMEPs and TRMPs propose to manage all spring/summer Chinook salmon fisheries to achieve escapement objectives. The FMEPs and TRMPs utilize a harvest rate with five tiers based on predicted adult abundance to each of the affected populations. The majority of the harvest is anticipated to come from hatchery-origin stocks. The FMEPs and TRMPs also describe a process to guide coordination of fishery design and implementation between the agencies implementing fisheries in the action area.

As required by the ESA 4(d) Rule for Tribal Plans (65 FR 42481, July 10, 2000 [50 CFR 223.209]), the Secretary must determine pursuant to 50 CFR 223.209 and pursuant to the government-to-government processes therein whether the TRMPs for fisheries in Northeast Oregon would appreciably reduce the likelihood of survival and recovery of Snake River spring/summer and Snake River Basin steelhead. The Secretary must take comments on his pending determination as to whether the TRMPs address the criteria in the Tribal 4(d) Rule and in § 223.203(b)(4).

As specified in § 223.203(b)(4) of the ESA 4(d) Rule, NMFS may approve an FMEP if it meets criteria set forth in § 223.203(b)(4)(i)(A) through (I). Prior to final approval of an FMEP, NMFS must publish notification announcing its availability for public review and comment.

NEPA requires Federal agencies to conduct an environmental analysis of their proposed actions to determine if the actions may affect the human environment. NMFS expects to take action on two ESA section 4(d) TRMPs and two ESA section 4(d) FMEPs. Therefore, NMFS is seeking public input on the scope of the required NEPA analysis, including the range of reasonable alternatives and associated impacts of any alternatives.

The final NEPA, TRMP, and FMEP determinations will not be completed until after the end of the 30-day comment period and will fully consider all public comments received during the comment period. NMFS will publish a record of its final action on the TRMPs in the **Federal Register**.

Authority

Under section 4 of the ESA, NMFS, by delegated authority from the Secretary of Commerce, is required to adopt such regulations as he deems necessary and advisable for the conservation of the species listed as threatened. The ESA salmon and steelhead 4(d) Rule (65 FR 42422, July 10, 2000) specifies categories of activities that contribute to the conservation of listed salmonids and sets out the criteria for such activities. Limit 4 of the updated 4(d) rule (50 CFR 223.203(b)(4)) further provides that the prohibitions of paragraph (a) of the updated 4(d) rule (50 CFR 223.203(a)) do not apply to activities associated with fishery harvest provided that an FMEP has been approved by NMFS to be in accordance with the salmon and steelhead 4(d) rule (65 FR 42422, July 10, 2000, as updated in 70 FR 37160, June 28, 2005). The ESA Tribal 4(d) Rule (65 FR 42481, July 10, 2000) states that the ESA section 9 take prohibitions will not apply to TRMPs that will not appreciably reduce the likelihood of survival and recovery for the listed species.

Dated: August 5, 2011.

Therese Conant,

Acting Chief, Endangered Species Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2011–20460 Filed 8–10–11; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XA629

Marine Mammals; File No. 15471–01

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; receipt of application for permit amendment.

SUMMARY: Notice is hereby given that Michael Adkesson, D.V.M., Chicago Zoological Society, 3300 Golf Rd., Brookfield, Illinois 60527, has applied for an amendment to Scientific Research Permit No. 15471.

DATES: Written, telefaxed, or e-mail comments must be received on or before September 12, 2011.

ADDRESSES: The application and related documents are available for review by selecting ''Records Open for Public Comment'' from the *Features* box on the Applications and Permits for Protected Species home page, *https://apps.nmfs.noaa.gov,* and then selecting File No. 15471–01 from the list of available applications.

These documents are also available upon written request or by appointment in the following office(s):

Permits, Conservation and Education Division, Office of Protected Resources, NMFS, 1315 East-West Highway, Room 13705, Silver Spring, MD 20910; phone (301) 427–8401; fax (301) 713–0376; and

Northeast Region, NMFS, 55 Great Republic Drive, Gloucester, MA 01930; phone (978) 281–9328; fax (978) 281–9394.

Written comments on this application should be submitted to the Chief, Permits, Conservation and Education Division, at the address listed above. Comments may also be submitted by facsimile to (301) 713–0376, or by e-mail to *NMFS.Pr1Comments@noaa.gov.* Please include File No. 15471–01 in the subject line of the e-mail comment.

Those individuals requesting a public hearing should submit a written request to the Chief, Permits, Conservation and

Education Division at the address listed above. The request should set forth the specific reasons why a hearing on this application would be appropriate.

FOR FURTHER INFORMATION CONTACT: Laura Morse or Jennifer Skidmore, (301) 427–8401.

SUPPLEMENTARY INFORMATION: The subject amendment to Permit No. 15471 is requested under the authority of the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), and the regulations governing the taking and importing of marine mammals (50 CFR part 216).

Permit No. 15471 (issued on August 23, 2010; 75 FR 52721), authorizes the permit holder to import biological samples taken for scientific research from South American fur seals (*Arctocephalus australis*). Unlimited samples from up to 200 salvaged carcasses and live female and pup South American fur seals may be received, imported, or exported annually. No live animals can be harassed or taken, lethally or otherwise, under the permit. The permit expires on August 31, 2015.

The permit holder is requesting the permit be amended to increase the total number of individuals and include samples from male South American fur seals. In addition, the permit holder is requesting to add adult and pup South American sea lions (*Otaria flavescens*) from which unlimited samples could be received, imported, or exported. No live animals would be harassed or taken, lethally or otherwise, under the requested amendment.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), an initial determination has been made that the activity proposed is categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

Concurrent with the publication of this notice in the **Federal Register**, NMFS is forwarding copies of this application to the Marine Mammal Commission and its Committee of Scientific Advisors.

Dated: August 5, 2011.

P. Michael Payne,

Chief, Permits, Conservation and Education Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2011–20458 Filed 8–10–11; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XA430

Takes of Marine Mammals Incidental to Specified Activities; Marine Geophysical Survey in the Central-Western Bering Sea, August 2011

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of an incidental take authorization (ITA).

SUMMARY: In accordance with the Marine Mammal Protection Act (MMPA) regulation, notification is hereby given that NMFS has issued an Incidental Harassment Authorization (IHA) to the U.S. Geological Survey (USGS) to take marine mammals, by Level B harassment, incidental to conducting a marine geophysical survey in the central-western Bering Sea, August 2011.

DATES: Effective August 7 through October 1, 2011.

ADDRESSES: A copy of the IHA and application are available by writing to P. Michael Payne, Chief, Permits, Conservation and Education Division, Office of Protected Resources, National Marine Fisheries Service, 1315 East-West Highway, Silver Spring, MD 20910 or by telephoning the contacts listed here.

A copy of the application containing a list of the references used in this document may be obtained by writing to the above address, telephoning the contact listed here (see **FOR FURTHER INFORMATION CONTACT**) or visiting the Internet at: *http://www.nmfs.noaa.gov/pr/permits/incidental.htm#applications.* The following associated documents are also available at the same Internet address: Environmental Assessment (EA), prepared by USGS. The NMFS Biological Opinion will be available online at: *http://www.nmfs.noaa.gov/pr/consultation/opinions.htm.* Documents cited in this notice may be viewed, by appointment, during regular business hours, at the aforementioned address.

FOR FURTHER INFORMATION CONTACT: Brian D. Hopper, 301–427–8401.

SUPPLEMENTARY INFORMATION:

Background

Section 101(a)(5)(D) of the MMPA (16 U.S.C. 1371 (a)(5)(D)) directs the Secretary of Commerce (Secretary) to authorize, upon request, the incidental, but not intentional, taking of small numbers of marine mammals of a species or population stock, by United States citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and, if the taking is limited to harassment, a notice of a proposed authorization is provided to the public for review.

Authorization for the incidental taking of small numbers of marine mammals shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s), and will not have an unmitigable adverse impact on the availability of the species or stock(s) for subsistence uses (where relevant). The authorization must set forth the permissible methods of taking, other means of effecting the least practicable adverse impact on the species or stock and its habitat, and requirements pertaining to the mitigation, monitoring and reporting of such takings. NMFS has defined ''negligible impact'' in 50 CFR 216.103 as ''* * * an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival.''

Section 101(a)(5)(D) of the MMPA established an expedited process by which citizens of the United States can apply for an authorization to incidentally take small numbers of marine mammals by harassment. Section 101(a)(5)(D) of the MMPA establishes a 45-day time limit for NMFS's review of an application followed by a 30-day public notice and comment period on any proposed authorizations for the incidental harassment of small numbers of marine mammals. Within 45 days of the close of the public comment period, NMFS must either issue or deny the authorization. Except with respect to certain activities not pertinent here, the MMPA defines ''harassment'' as:

> any act of pursuit, torment, or annoyance which (i) has the potential to injure a marine mammal or marine mammal stock in the wild [Level A harassment]; or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering [Level B harassment].

16 U.S.C. 1362(18)

Summary of Request

NMFS received an application on April 8, 2011, from USGS for the taking by harassment, of marine mammals, incidental to conducting a marine geophysical survey in the central-western Bering Sea within the U.S. Exclusive Economic Zone (EEZ) and adjacent international waters in depths greater than 3,000 m (9,842 ft). USGS plans to conduct the survey from approximately August 7 to September 1, 2011. On June 8, 2011, NMFS published a notice in the **Federal Register** (76 FR 33246) discussing the effects on marine mammals and making preliminary determinations regarding a proposed IHA. The notice initiated a 30 day public comment period, which closed on July 8, 2011.

USGS plans to use one source vessel, the R/V *Marcus G. Langseth* (*Langseth*) and a seismic airgun array to collect seismic reflection and refraction profiles to be used to delineate the U.S. Extended Continental Shelf (ECS) in the central-western Bering Sea. In addition to the operations of the seismic airgun array, USGS intends to operate a multibeam echosounder (MBES) and a sub-bottom profiler (SBP) continuously throughout the survey.

Acoustic stimuli (*i.e.,* increased underwater sound) generated during the operation of the seismic airgun array may have the potential to cause a short-term behavioral disturbance for marine mammals in the survey area. This is the principal means of marine mammal taking associated with these activities and USGS has requested an authorization to take 12 species of marine mammals by Level B harassment. Take is not expected to result from the use of the MBES or SBP, for reasons discussed in this notice; nor is take expected to result from collision with the vessel because it is a single vessel moving at a relatively slow speed during seismic acquisition within the survey, for a relatively short period of time (approximately 21 days). It is likely that any marine mammal would be able to avoid the vessel.

Description of the Specified Activity

USGS plans to conduct the seismic survey in the central-western Bering Sea between approximately 350 and 800 kilometers (km) (189 and 432 nautical miles (nmi)) offshore in the area 55° to 58.5° North, 177° West to 175° East. The survey will take place in the U.S. Exclusive Economic Zone (EEZ) and adjacent international waters in water depths greater than 3,000 meters (m) (9,842 feet (ft)). The project is scheduled to occur from approximately August 7 to September 1, 2011. Some minor deviation from these dates is possible, depending on logistics and weather.

The seismic survey will collect seismic reflection and refraction profiles to be used to delineate the U.S. ECS in the Bering Sea. The ECS is the region beyond 200 nmi where a nation can show that it satisfies the conditions of Article 76 of the United Nations Convention on the Law of the Sea. One of the conditions in Article 76 is a function of sediment thickness. The seismic profiles are designed to identify the stratigraphic ''basement'' and to map the thickness of the overlying sediments. Acoustic velocities (required to convert measured travel times to true depth) will be measured directly using sonobuoys and ocean-bottom seismometers (OBSs), as well as by analysis of hydrophone streamer data. Acoustic velocity refers to the velocity of sound through sediments or crust.

The survey will involve one source vessel, the *Langseth.* The *Langseth* will deploy an array of 36 airguns as an energy source. The receiving system will consist of one 8 km (4.3 nmi) long hydrophone streamer and/or five OBSs. As the airgun is towed along the survey lines, the hydrophone streamer will receive the returning acoustic signals and transfer the data to the on-board processing system. The OBSs record the returning acoustic signals internally for later analysis.

The planned seismic survey will consist of approximately 2,240 km of transect lines in the central-western Bering Sea survey area, with an additional 140 km (75.6 nmi) of turns. During turns, the array will be powered-down to one 40 in^3 airgun. All of the survey will take place in water deeper than 3,000 m (9,842 ft). A multi-channel seismic (MCS) survey using the hydrophone streamer will take place along 14 lines. Following the MCS survey, 18 OBSs will be deployed and a refraction survey will take place along three of the 14 lines. If time permits, an additional 525 km of contingency lines will be added to the MCS survey. In addition to the the airgun array, a Kongsberg EM 122 MBES and Knudsen 320B SBP will be operated from the *Langseth* continuously throughout the cruise. There will be additional seismic operations associated with equipment testing, start-up, and possible line changes or repeat coverage of any areas where initial data quality is sub-standard. In USGS's calculations, 25 percent has been added for those additional operations.

All planned geophysical data acquisition activities will be conducted by Lamont-Doherty Earth Observatory (L–DEO), the *Langseth's* operator, with on-board assistance by the scientists who have planned the study. The Principal Investigators are Drs. Jonathan R. Childs and Ginger Barth of the USGS. The vessel will be self-contained, and the crew will live aboard the vessel for the entire cruise.

Description of the Dates, Duration, and Specified Geographic Region

The survey will occur in the central-western Bering Sea between approximately 350 and 800 kilometers (km) (189 and 432 nautical miles (nmi)) offshore in the area 55° to 58.5° North, 177° West to 175° East. The seismic survey will take place in water depths greater than 3,000 m. The exact dates of the activities depend on logistics and weather conditions. The *Langseth* will depart from Dutch Harbor, Alaska on August 7, 2011, and return there on September 1, 2011. Seismic operations will be carried out for an estimated 18 to 21 days.

NMFS outlined the purpose of the program in a previous notice for the proposed IHA (76 FR 33246, June 8, 2011). The activities to be conducted have not changed between the proposed IHA notice and this final notice announcing the issuance of the IHA. For a more detailed description of the authorized action, including vessel and acoustic source specifications, the reader should refer to the proposed IHA notice (76 FR 33246, June 8, 2011), the IHA application and associated documents referenced above this section.

Comments and Responses

A notice of receipt of the USGS application and proposed IHA was published in the **Federal Register** on June 8, 2011 (76 FR 33246). During the 30-day public comment period, NMFS only received comments from the Marine Mammal Commission (Commission). The Commission's comments are online at: *http://www.nmfs.noaa.gov/pr/permits/incidental.htm.* Following are their comments and NMFS's responses:

Comment 1: The Commission recommends that the NMFS require the USGS to re-estimate the proposed exclusion and buffer zones and associated takes of marine mammals using site-specific information.

Response: In the water depths that the survey is to be conducted, site-specific source signature measurements are neither warranted nor practical. Site signature measurements are normally conducted commercially by shooting a test pattern over an ocean bottom instrument in shallow water. This method is neither practical nor valid in water depths as great as 3,000 m (9,842.5 ft). The alternative method of conducting site-specific attenuation measurements would require a second vessel, which is impractical both logistically and financially. Sound propagation varies noticeably less between deep water sites than between shallow water sites (because of the reduced significance of bottom interaction), thus decreasing the importance of site-specific estimates.

Based on these reasons, and the information provided by USGS in their IHA application and EA, NMFS is satisfied that the data supplied are sufficient for NMFS to conduct its analysis and make any determinations; therefore, no further effort is needed by the applicant. While exposures of marine mammals to acoustic stimuli are difficult to estimate, NMFS is confident that the levels of take authorized herein are estimated based upon the best available scientific information and estimation methodology. The 160 dB zone used to estimate exposure is appropriate and sufficient for purposes of supporting NMFS's analysis and determinations required under section 101(a)(5)(D) of the MMPA and its implementing regulations. See NMFS's response to Comment 2 (below) for additional details.

Comment 2: The Commission recommends that, if site-specific information is not used to estimate the proposed exclusion and buffer zones and associated takes of marine mammals, the USGS provide a detailed justification for the exclusion and buffer zones applicable to the proposed survey in the Bering Sea, which are based on either empirical data collected in the GOM or on modeling that uses measurements from the GOM, and explain the significance of any deviations in survey method, such as the proposed change in tow depth.

Response: USGS has revised Appendix A in the EA to include information from the calibration study conducted on the *Langseth* in 2007 and 2008. This information is now available in the final EA on USGS's Web site at *http://walrus.wr.usgs.gov/EA/ECS_EA/* as well as on NSF's Web site at *http://www.nsf.gov/geo/oce/envcomp/index.jsp.* The revised Appendix A describes the L–DEO modeling process and compares the model results with empirical results of the 2007 to 2008 *Langseth* calibration experiment in shallow, intermediate, and deep water. The conclusions identified in Appendix A show that the model represents the actual produced levels, particularly within the first few kms, where the predicted exclusion zones (EZs, *i.e.,* safety radii) lie. At greater distances, local oceanographic variations begin to take effect, and the model tends to over predict. Further, since the modeling matches the observed measurement data, the authors have concluded that the models can continue to be used for defining EZs, including for predicting mitigation radii for various tow depths. The data results from the studies were peer reviewed and the calibration results, viewed as conservative, were used to determine the cruise-specific EZs.

At present, the L–DEO model does not account for site-specific environmental conditions. The calibration study of the L–DEO model predicted that using site-specific information may actually provide less conservative EZ radii at greater distances. The Draft Programmatic Environmental Impact Statement for Marine Seismic Research Funded by the National Science Foundation or Conducted by the U.S. Geological Survey (DPEIS) prepared pursuant to the National Environmental Policy Act (NEPA; 42 U.S.C. 4321 *et seq.*) did incorporate various site-specific environmental conditions in the modeling of the Detailed Analysis Areas. The NEPA process associated with the DPEIS is still ongoing and the USGS and NSF have not yet issued a Record of Decision. Once the NEPA process for the PEIS has concluded, USGS and/or NSF will look at upcoming cruises on a site-specific basis for any impacts not already considered in the DPEIS.

The IHA issued to USGS, under section 101(a)(5)(D) of the MMPA provides monitoring and mitigation requirements that will protect marine mammals from injury, serious injury, or mortality. USGS is required to comply with the IHA's requirements. These analyses are supported by extensive scientific research and data. NMFS is confident in the peer-reviewed results of the L–DEO seismic calibration studies which, although viewed as conservative, are used to determine cruise-specific EZs and which factor into exposure estimates. NMFS has determined that these reviews are the best scientific data available for review of the IHA application and to support the necessary analyses and determinations under the MMPA, Endangered Species Act (ESA; 16 U.S.C. 1531 *et seq.*) and NEPA.

Based on NMFS's analysis of the likely effects of the specified activity on marine mammals and their habitat, NMFS has determined that the EZs identified in the IHA are appropriate for the survey and that additional field measurement is not necessary at this time. While exposures of marine mammals to acoustic stimuli are difficult to estimate, NMFS is confident that the levels of take authorized have been estimated based upon the best available scientific information and estimation methodology. The 160 dB zone used to estimate exposure is appropriate and sufficient for purposes of supporting NMFS's analysis and determinations required under section 101(a)(5)(D) of the MMPA and its implementing regulations.

Comment 3: The Commission recommends that the NMFS specify in the authorization all conditions under which an 8 min period could be followed by a resumption of the airguns at full power.

Response: In the instance of a power-down or shut-down based on the presence of a marine mammal in the EZ, USGS will restart the airgun array to the full operating source level (*i.e.,* 36 airguns 6,600 in^3) only if the PSVO visually observes the marine mammal exiting the EZ for the full source level within an 8 min period of the shut-down or power-down. The 8 min period is based on the 180 dB radius for the 36 airgun subarray at a depth of 9 m in relation to the minimum planned speed of the *Langseth* while shooting (8.5 km/hr (4.6 kts)). In the event that a marine mammal would re-enter the EZ after reactivating the airguns, USGS would reinitiate a shut-down or power-down as required by the IHA.

Should the airguns be inactive or powered-down for more than 8 min, and the PSVO does not observe the marine mammal leaving the EZ, then USGS must wait 15 min (for small odontocetes and pinnipeds) or 30 min (for mysticetes and large odontocetes) after the last sighting before USGS can initiate ramp-up procedures. However, ramp-up will not occur as long as a marine mammal is detected within the EZ, which provides more time for animals to leave the EZ, and accounts for the position, swim speed, and heading for marine mammals within the EZ.

Finally, USGS may need to temporarily perform a shut-down due to equipment failure or maintenance. In this instance, USGS will restart the airgun array to the full source level within an 8 min period of the shut down only if the PSVOs do not observe marine mammals within the EZ for the full source level. If the airguns are inactive or powered-down for more than 8 min, USGS would follow the ramp-up procedures required by the IHA. USGS would restart the airguns beginning with the smallest airgun in the array and add airguns in a sequence such that the source level of the array does not exceed approximately 6 decibels (dB) per 5 min period over a total duration of approximately 30 min. Again, the PSVOs would monitor the EZs for marine mammals during this time and would initiate a power-down or a shut-down, as required by the IHA.

Comment 4: The Commission recommends that the NMFS extend the 30 min period following a marine mammal sighting in the EZ to cover the full dive times of all species likely to be encountered.

Response: NMFS recognizes that several species of deep-diving cetaceans are capable of remaining underwater for more than 30 min (*e.g.,* sperm whales, Cuvier's beaked whales, Baird's beaked whales); however, for the following reasons NMFS believes that 30 min is an adequate length for the monitoring period prior to the ramp-up of airguns:

(1) Because the *Langseth* is required to monitor before ramp-up of the airgun array, the time of monitoring prior to start-up of any but the smallest array is effectively longer than 30 min (ramp-up will begin with the smallest airgun in the array and airguns will be added in sequence such that the source level of the array will increase in steps not exceeding approximately 6 dB per 5 min period over a total duration of 20 to 30 min;

(2) In many cases PSVOs are observing during times when USGS is not operating the seismic airguns and would observe the area prior to the 30 min observation period;

(3) The majority of the species that may be exposed do not stay underwater more than 30 min; and

(4) All else being equal and if deep-diving individuals happened to be in the area in the short time immediately prior to the pre-ramp-up monitoring, if an animal's maximum underwater dive time is 45 min, then there is only a one in three chance that the last random surfacing would occur prior to the beginning of the required 30 min monitoring period and that the animal would not be seen during that 30 min period.

Finally, seismic vessels are moving continuously (because of the long, towed array and streamer) and NMFS believes that unless the animal submerges and follows at the speed of the vessel (highly unlikely, especially when considering that a significant part of their movements is vertical (deep-diving)), the vessel will be far beyond the length of the EZ radii within 30 min, and therefore it will be safe to start the airguns again.

Under the MMPA, incidental take authorizations must include means of effecting the least practicable adverse impact on marine mammal species and their habitat. Monitoring and mitigation measures are designed to comply with this requirement. NMFS believes that the framework for visual monitoring will: (1) Be effective at spotting almost all species for which take is requested; and (2) that imposing additional requirements, such as those suggested by the Commission, would not meaningfully increase the effectiveness of observing marine mammals approaching or entering the EZs and thus further minimize the potential for take.

Comment 5: The Commission recommends that the NMFS provide additional justification for its preliminary determination that the proposed monitoring program will be sufficient to detect, with a high level of confidence, all marine mammals within or entering the identified exclusion and buffer zones, which at a minimum should:

(1) Identify those species that it believes can be detected with a high degree of confidence using visual monitoring only;

(2) Describe detection probability as a function of distance from the vessel;

(3) Describe changes in detection probability under various sea state and weather conditions and light levels; and

(4) Explain how close to the vessel marine mammals must be for Protected Species Observers (PSOs) to achieve high nighttime detection rates.

Response: NMFS believes that the planned monitoring program will be sufficient to detect (using visual monitoring and passive acoustic monitoring (PAM)), with reasonable certainty, marine mammals within or entering identified EZs. This monitoring, along with the required mitigation measures, will result in the least practicable adverse impact on the affected species or stocks and will result in a negligible impact on the affected species or stocks of marine mammals. Also, NMFS expects some animals to avoid areas around the airgun area ensonified at the level of the EZ.

NMFS acknowledges that the detection probability for certain species of marine mammals varies depending on animal size and behavior as well as sea state and weather conditions and light levels. The detectability of marine mammals likely decreases in low light (*i.e.,* darkness), higher Beaufort sea states and wind conditions, and poor weather (*e.g.,* fog and/or rain). However, at present, NMFS views the combination of visual monitoring and PAM as the most effective monitoring and mitigation techniques available for detecting marine mammals within or entering the EZ. The final monitoring and mitigation measures are the most effective feasible measures and NMFS is not aware of any additional measures which could meaningfully increase the likelihood of detecting marine mammals in and around the EZ. Further, public comment has not revealed any additional monitoring or mitigation measures that could be feasibly implemented to increase the effectiveness of detection.

USGS (the Federal funding agency for this survey), National Science Foundation (NSF), and L–DEO are receptive to incorporating proven technologies and techniques to enhance the current monitoring and mitigation program. Until proven technological advances are made, nighttime mitigation measures during operations include combinations of the use of Protected Species Visual Observers (PSVOs) for ramp-ups, PAM, night vision devices (NVDs), and continuous shooting of a mitigation airgun. Should the airgun array be powered-down, the operation of a single airgun would continue to serve as a sound source deterrent to marine mammals. In the event of a complete shut-down of the airgun array at night for mitigation or repairs, USGS suspends the data collection until one-half hour after nautical twilight-dawn (when PSVO's are able to clear the EZ). USGS will not activate the airguns until the entire EZ is visible for at least 30 min.

In cooperation with NMFS, L–DEO will be conducting efficacy experiments of NVDs during a future *Langseth* cruise. In addition, in response to a recommendation from NMFS, L–DEO is evaluating the use of handheld forward-looking thermal imaging cameras to supplement nighttime monitoring and mitigation practices. During other low power seismic and seafloor mapping surveys, USGS successfully used these devices while conducting nighttime seismic operations.

Comment 6: The Commission recommends that the NMFS consult with the funding agency (*i.e.,* NSF) and individual applicants (*e.g.,* USGS and L–DEO) to develop, validate, and implement a monitoring program that provides a scientifically sound, reasonably accurate assessment of the types of marine mammal taking and the number of marine mammals taken.

Response: Numerous studies have reported on the abundance and distribution of marine mammals inhabiting the Bering Sea, which overlaps with the seismic survey area, and USGS has incorporated this data into their analyses used to predict marine mammal take in their application. NMFS believes that USGS's current approach for estimating abundance in the survey area (prior to the survey) is the best available approach.

There will be significant amounts of transit time during the cruise, and PSVOs will be on watch prior to and after the seismic portions of the survey, in addition to during the survey. The collection of this visual observational data by PSVOs may contribute to baseline data on marine mammals (presence/absence) and provide some generalized support for estimated take numbers, but it is unlikely that the information gathered from this single cruise alone would result in any statistically robust conclusions for any particular species because of the small number of animals typically observed.

NMFS acknowledges the Commission's recommendations and is open to further coordination with the Commission, USGS (the Federal research funding agency for this cruise), NSF (the vessel owner), and L–DEO (the ship operator on behalf of NSF), to develop, validate, and implement a monitoring program that will provide or contribute towards a more scientifically sound and reasonably accurate assessment of the types of marine mammal taking and the number of marine mammals taken. However, the cruise's primary focus is marine geophysical research and the survey may be operationally limited due to considerations such as location, time, fuel, services, and other resources.

Comment 7: The Commission recommends that NMFS require the applicant:

(1) To report on the number of marine mammals that were detected acoustically and for which a power-down or shut-down of the airguns was initiated;

(2) Specify if such animals also were detected visually; and

(3) Compare the results from the two monitoring methods (visual versus acoustic) to help identify their respective strengths and weaknesses.

Response: The IHA requires that PSAOs on the *Langseth* do and record the following when a marine mammal is detected by the PAM:

(1) Notify the on-duty PSVO(s) immediately of a vocalizing marine mammal so a power-down or shut-down can be initiated, if required;

(2) Enter the information regarding the vocalization into a database. The data to be entered include an acoustic encounter identification number, whether it was linked with a visual sighting, date, time when first and last heard and whenever any additional information was recorded, position, and water depth when first detected, bearing if determinable, species or species group (*e.g.,* unidentified dolphin, sperm whale), types and nature of sounds heard (*e.g.,* clicks, continuous, sporadic, whistles, creaks, burst pulses, strength of signal, *etc.*), and any other notable information.

USGS reports on the number of acoustic detections made by the PAM system within the post-cruise monitoring reports as required by the IHA. The report also includes a description of any acoustic detections that were concurrent with visual sightings, which allows for a comparison of acoustic and visual detection methods for each cruise.

The post-cruise monitoring reports also include the following information: the total operational effort in daylight (hrs), the total operational effort at night (hrs), the total number of hours of visual observations conducted, the total number of sightings, and the total number of hours of acoustic detections conducted.

LGL Ltd., Environmental Research Associates (LGL), a contractor for USGS, has processed sighting and density data, and their publications can be viewed online at: *http://www.lgl.com/index.php?option=com_content&view=article&id=69&Itemid=162&lang=en.* Post-cruise monitoring reports are currently available on the NMFS's MMPA Incidental Take Program Web site and future reports will also be available on the NSF Web site should there be interest in further analysis of this data by the public.

Comment 8: The Commission recommends that NMFS condition the authorization, if issued, to require the USGS to monitor, document, and report observations during all ramp-up procedures; this data will provide a stronger scientific basis for determining the effectiveness of and deciding when to implement this particular mitigation measure.

Response: The IHA requires that PSVOs on the *Langseth* make observations for 30 min prior to ramp-up, during all ramp-ups, and during all daytime seismic operations and record the following information when a marine mammal is sighted:

(1) Species, group size, age/size/sex categories (if determinable), behavior when first sighted and after initial sighting, heading (if consistent), bearing and distance from seismic vessel, sighting cue, apparent reaction of the airguns or vessel (*e.g.,* none, avoidance, approach, paralleling, *etc.,* and including responses to ramp-up), and behavioral pace; and

(2) Time, location, heading, speed, activity of the vessel (including number of airguns operating and whether in state of ramp-up or power-down), Beaufort wind force and sea state, visibility, and sun glare.

Comment 9: The Commission recommends that NMFS in collaboration with the NSF, analyze these data to determine the effectiveness of ramp-up procedures as a mitigation measure for geophysical surveys.

Response: One of the primary purposes of monitoring is to result in ''increased knowledge of the species'' and the effectiveness of monitoring and mitigation measures; the effectiveness of ramp-up as a mitigation measure and marine mammal reaction to ramp-up would be useful information in this regard. NMFS has asked USGS, NSF, and L–DEO to gather all data that could potentially provide information regarding the effectiveness of ramp-ups as a mitigation measure. However, considering the low numbers of marine mammal sightings and low numbers of ramp-ups, it is unlikely that the information will result in any statistically robust conclusions for this particular seismic survey. Over the long term, these requirements may provide information regarding the effectiveness of ramp-up as a mitigation measure, provided animals are detected during ramp up.

Description of the Marine Mammals in the Area of the Specified Activity

Twenty marine mammal species (14 cetacean and 6 pinniped) are known to or could occur in the central-western Bering Sea. Several of these species are listed as endangered under the U.S. Endangered Species Act of 1973 (ESA; 16 U.S.C. 1531 *et seq.*), including the North Pacific right whale (*Eubalaena japonica*), bowhead (*Balaena mysticetus*), humpback (*Megaptera novaeangliae*), sei (*Balaenoptera borealis*), fin (*Balaenoptera physalus*), blue (*Balaenoptera musculus*), and sperm (*Physeter macrocephalus*) whales, as well as the western stock of Steller sea lions (*Eumetopias jubatus*). The eastern stock of Steller sea lions is listed as threatened.

The marine mammals that occur in the survey area belong to three taxonomic groups: odontocetes (toothed cetaceans, such as dolphins), mysticetes (baleen whales), and pinnipeds (seals, sea lions, and walrus). Cetaceans and pinnipeds are the subject of the IHA application to NMFS. Walrus sightings are rare in the Bering Sea during the summer. The U.S. Fish and Wildlife Service (USFWS) manages the Pacific walrus and they are not considered further in this analysis; all others species are managed by NMFS. Coastal cetacean species (gray whales) likely would not be encountered in the deep, offshore waters of the survey area.

Table 1 presents information on the abundance, distribution, population status, conservation status, and density of the marine mammals that may occur in the survey area during August 2011.

TABLE 1—THE HABITAT, REGIONAL ABUNDANCE, AND CONSERVATION STATUS OF MARINE MAMMALS THAT MAY OCCUR IN OR NEAR THE SEISMIC SURVEY AREAS IN THE CENTRAL-WESTERN BERING SEA (SEE TEXT AND TABLE 2 IN USGS'S APPLICATION AND EA FOR FURTHER DETAILS)

Species	Occurrence in/near survey area	Habitat	Regional abundance	ESA [1]	MMPA [2]	Density (number/1,000 km²)	
						Best [3]	Max [4]
Mysticetes:							
North Pacific right whale (*Eubalaena japonica*).	Rare	Coastal, shelf, offshore.	Low hundreds [5]	EN	D	0	0
Bowhead whale (*Balaena mysticetus*).	Uncommon	Pack ice, coastal	12,631 [6]	EN	D	0	0
Gray whale (*Eschrichtius robustus*).	Common	Coastal, shallow shelf.	NW Pacific: 19,126 NE Pacific: ~100 [7].	DL/E [8]	NC D (Western populations)	0.01	0.12
Humpback whale (*Megaptera novaeangliae*).	Common	Offshore, nearshore in winter.	20,800 [9]	EN	D	0.40	1.04
Minke whale (*Balaenoptera acutorostrata*).	Common	Nearshore, offshore, ice.	25,000 [10]	NL	NC	1.23	4.10
Sei whale (*Balaenoptera borealis*).	Uncommon	Offshore, shelf	7,260 to 12,620 [11]	EN	D	0.05	0.58
Fin whale (*Balaenoptera physalus*).	Common	Offshore, deep water.	13,620 to 18,680 [12]	EN	D	3.94	17.00
Blue whale (*Balaneoptera musculus*).	Rare	Offshore, shelf, coastal.	3,500 [13]	EN	D	0	0
Odontocetes:							
Sperm whale (*Physeter macrocephalus*).	Uncommon	Offshore	24,000 [14]	EN	D	0.07	0.14
Cuvier's beaked whale (*Ziphius cavirostris*).	Very rare	Offshore	20,000 [15]	NL	NC	0	0
Baird's beaked whale (*Berardius bairdii*).	Rare	Offshore	7,000 [16]	NL	NC	0.07	0.10
Stejneger's beaked whale (*Mesoplodon stejnegeri*).	Uncommon	Offshore	N.A.	NL	NC	0.04	0.12
Pacific white-sided dolphin (*Lagenorhynchus obliquidens*).	Rare	Pelagic, shelf, coastal.	988,000 [17]	NL	NC	0.03	0.04
Killer whale (*Orcinus orca*).	Common	Pelagic, shelf, coastal.	8,500 [18]	NL	NC	2.82	3.96
Dall's porpoise (*Phocoenoides dalli*).	Common	Nearshore, offshore	1,186,000 [19]	NL	NC	8.86	18.25
Pinnipeds:							
Northern fur seal (*Callorhinus ursinus*).	Common	Offshore and coastal.	1.1 million [20]	NL	D	28.5	42.75
Steller sea lion (*Eumetopias jubatus*).	Common	Coastal	58,334, 72,223 [21], 42,366 [22].	T [23], EN [23]	D	2.70	4.05
Spotted seal (*Phoca largha*).	Uncommon	Ice	AK: ~59,214 [24]	NL	....	N.A.	N.A.
Ringed seal (*Pusa hispida*).	Uncommon	Ice, landfast, pack	AK: 249,000 [24]	NL	NC	N.A.	N.A.

TABLE 1—THE HABITAT, REGIONAL ABUNDANCE, AND CONSERVATION STATUS OF MARINE MAMMALS THAT MAY OCCUR IN OR NEAR THE SEISMIC SURVEY AREAS IN THE CENTRAL-WESTERN BERING SEA (SEE TEXT AND TABLE 2 IN USGS'S APPLICATION AND EA FOR FURTHER DETAILS)—Continued

Species	Occurrence in/near survey area	Habitat	Regional abundance	ESA [1]	MMPA [2]	Density (number/1,000 km²)	
						Best [3]	Max [4]
Ribbon seal (*Histriophoca fasciata*).	Common	Ice	Bering Sea: 90,000–100,000 [24].	NL	NC	43.60	65.40

N.A. Not available or not assessed.
[1] U.S. Endangered Species Act: EN = Endangered, T = Threatened, NL = Not listed.
[2] U.S. Marine Mammal Protection Act: D = Depleted, NC = Not Classified.
[3] Best density estimate as listed in Table 3 of the application.
[4] Maximum density estimate as listed in Table 3 of the application.
[5] Western population (Brownell *et al.,* 2001)
[6] Based on 2003–2005 surveys (Koski *et al.,* 2010).
[7] Northwest (NW) Pacific (Allen and Angliss, 2010); Northeast (NE) Pacific (Reilly *et al.,* 2008).
[8] The western (Northeast Pacific) subpopulation is listed as Endangered.
[9] North Pacific Ocean (Barlow *et al.,* 2009).
[10] Northwest Pacific (Buckland *et al.,* 1992; IWC, 2010).
[11] North Pacific (Tillman, 1977).
[12] North Pacific (Ohsumi and Wada, 1974).
[13] Eastern North Pacific (NMFS, 1998).
[14] Eastern temperate North Pacific (Whitehead, 2002b).
[15] Eastern Tropical Pacific (Wade and Gerrodette, 1993).
[16] Western North Pacific (Reeves and Leatherwood, 1994; Kasuya, 2002).
[17] North Pacific Ocean (Miyashita, 1993b).
[18] Eastern Tropical Pacific (Ford, 2002).
[19] North Pacific Ocean and Bering Sea (Houck and Jefferson, 1999).
[20] North Pacific (Gelatt and Lowry, 2008).
[21] Eastern U.S. Stock (Allen and Angliss, 2010).
[22] Western U.S. Stock (Allen and Angliss, 2010).
[23] Eastern stock is listed as threatened, and the western stock is listed as endangered.
[24] Burns 1981.

Refer to Section III of USGS's application for detailed information regarding the abundance and distribution, population status, and life history and behavior of these species and their occurrence in the project area. The application also presents how USGS calculated the estimated densities for the marine mammals in the survey area. NMFS has reviewed these data and determined them to be the best available scientific information for the purposes of the IHA.

Potential Effects on Marine Mammals

Acoustic stimuli generated by the operation of the airguns, which introduce sound into the marine environment, may have the potential to cause Level B harassment of marine mammals in the survey area. The effects of sounds from airgun operations might include one or more of the following: tolerance, masking of natural sounds, behavioral disturbance, temporary or permanent hearing impairment, or non-auditory physical or physiological effects (Richardson *et al.,* 1995; Gordon *et al.,* 2004; Nowacek *et al.,* 2007; Southall *et al.,* 2007).

Permanent hearing impairment, in the unlikely event that it occurred, would constitute injury, but temporary threshold shift (TTS) is not an injury (Southall *et al.,* 2007). Although the possibility cannot be entirely excluded, it is unlikely that the project would result in any cases of temporary or permanent hearing impairment, or any significant non-auditory physical or physiological effects. Based on the available data and studies described here, some behavioral disturbance is expected, but NMFS expects the disturbance to be localized and short-term.

The notice of the proposed IHA (76 FR 33246, June 8, 2011) included a discussion of the effects of sounds from airguns on mysticetes, odontocetes, and pinnipeds including tolerance, masking, behavioral disturbance, hearing impairment, and other non-auditory physical effects. NMFS refers the reader to USGS's application, and EA for additional information on the behavioral reactions (or lack thereof) by all types of marine mammals to seismic vessels.

Anticipated Effects on Marine Mammal Habitat

NMFS included a detailed discussion of the potential effects of this action on marine mammal habitat, including physiological and behavioral effects on marine fish and invertebrates in the notice of the proposed IHA (76 FR 33246, June 8, 2011). While NMFS anticipates that the specified activity may result in marine mammals avoiding certain areas due to temporary ensonification, this impact to habitat is temporary and site-specific, which NMFS considered in greater detail in the notice of the proposed IHA (76 FR 33246, June 8, 2011) as behavioral modification. The main impact associated with the activity would be temporarily elevated noise levels and the associated direct effects on marine mammals.

Mitigation

In order to issue an ITA under section 101(a)(5)(D) of the MMPA, NMFS must set forth the permissible methods of taking pursuant to such activity, and other means of effecting the least practicable adverse impact on such species or stock and its habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and the availability of such species or stock for taking for certain subsistence uses.

USGS based the mitigation measures to be implemented for the seismic survey on the following:

(1) Protocols used during previous USGS and L–DEO seismic research cruises as approved by NMFS;

(2) Previous IHA applications and IHAs approved and authorized by NMFS; and

(3) Recommended best practices in Richardson *et al.* (1995), Pierson *et al.* (1998), and Weir and Dolman (2007).

To reduce the potential for disturbance from acoustic stimuli associated with the activities, USGS and/or its designees will implement the following mitigation measures for marine mammals:

(1) EZs;
(2) Power-down procedures;
(3) Shut-down procedures;
(4) Ramp-up procedures; and
(5) Special procedures for situations and species of concern.

Planning Phase—In designing the seismic survey, USGS has considered potential environmental impacts including seasonal, biological, and weather factors; ship schedules; and equipment availability. Part of the considerations was whether the research objectives could be met with a smaller source; tests will be conducted to determine whether the two-string sub-array (3,300 in^3) will be satisfactory to accomplish the geophysical objectives. If so, the smaller array will be used to minimize environmental impact. Also, the array will be powered-down to a single airgun during turns, and the array will be shut-down during OBS deployment and retrieval.

EZs—Received sound levels have been determined by corrected empirical measurements for the 36 airgun array, and the L–DEO model was used to predict the EZs for the single 1900LL 40 in^3 airgun, which will be used during power-downs. Results were recently reported for propagation measurements of pulses from the 36 airgun array in two water depths (approximately 1,600 m and 50 m (5,249 to 164 ft)) in the Gulf of Mexico (GOM) in 2007 to 2008 (Tolstoy *et al.,* 2009). It would be prudent to use the empirical values that resulted to determine EZs for the airgun array. Results of the propagation measurements (Tolstoy *et al.,* 2009) showed that radii around the airguns for various received levels varied with water depth. During the study, all survey effort will take place in deep (greater than 1,000 m) water, so propagation in shallow water is not relevant here. The depth of the array was different in the GOM calibration study (6 m (19.7 ft)) than in the survey (9 m); thus, correction factors have been applied to the distances reported by Tolstoy *et al.* (2009). The correction factors used were the ratios of the 160, 180, and 190 dB distances from the modeled results for the 6,600 in^3 airgun array towed at 6 m versus 9 m. Based on the propagation measurements and modeling, the distances from the source where sound levels are predicted to be 190, 180, and 160 dB re 1 μPa (rms) were determined. The 180 and 190 dB radii are to 940 m and 400 m, respectively, as specified by NMFS (2000); these levels were used to establish the EZs.

If the PSVO detects marine mammal(s) within or about to enter the appropriate EZ, the airguns will be powered-down (or shut-down, if necessary) immediately.

Table 2 summarizes the predicted distances at which sound levels (160, 180, and 190 dB (rms)) are expected to be received from the 36 airgun array and a single airgun operating in deep water depths.

TABLE 2—MEASURED (ARRAY) OR PREDICTED (SINGLE AIRGUN) DISTANCES TO WHICH SOUND LEVELS ≥190, 180, AND 160 DB RE: 1 μPA (RMS) COULD BE RECEIVED IN WATER DEPTHS >1,000 M DURING THE SURVEY IN THE CENTRAL-WESTERN BERING SEA, AUGUST 2011

Source and volume	Water depth	Predicted RMS distances (m)		
		190 dB	180 dB	160 dB
Single Bolt airgun (40 in^3)	Deep >1,000 m	12	40	385
4 Strings 36 airguns (6,600 in^3)	Deep >1,000 m	400	940	3,850

Power-down Procedures—A power-down involves decreasing the number of airguns in use such that the radius of the 180 dB (or 190 dB) zone is decreased to the extent that marine mammals are no longer in or about to enter the EZ. A power-down of the airgun array can also occur when the vessel is moving from one seismic line to another. During a power-down for mitigation, USGS will operate one airgun. The continued operation of one airgun is intended to alert marine mammals to the presence of the seismic vessel in the area. In contrast, a shut-down occurs when the *Langseth* suspends all airgun activity.

If the PSVO detects a marine mammal outside the EZ, but it is likely to enter the EZ, USGS will power-down the airguns before the animal is within the EZ. Likewise, if a mammal is already within the EZ, when first detected USGS will power-down the airguns immediately. During a power-down of the airgun array, USGS will also operate the 40 in^3 airgun. If a marine mammal is detected within or near the smaller EZ around that single airgun, USGS will shut-down the airgun (see next section).

Following a power-down, USGS will not resume airgun activity until the marine mammal has cleared the EZ. USGS will consider the animal to have cleared the EZ if:

• A PSVO has visually observed the animal leave the EZ, or

• A PSVO has not sighted the animal within the EZ for 15 min for species with shorter dive durations (*i.e.,* small odontocetes or pinnipeds), or 30 min for species with longer dive durations (*i.e.,* mysticetes and large odontocetes, including sperm, pygmy sperm, dwarf sperm, killer, and beaked whales).

During airgun operations following a power-down (or shut-down) whose duration has exceeded the time limits specified previously, USGS will ramp-up the airgun array gradually (see Shut-down and Ramp-up Procedures).

Shut-down Procedures—USGS will shut down the operating airgun(s) if a marine mammal is seen within or approaching the EZ for the single airgun. USGS will implement a shut-down:

(1) If an animal enters the EZ of the single airgun after USGS has initiated a power-down; or

(2) If an animal is initially seen within the EZ of the single airgun when more than one airgun (typically the full airgun array) is operating.

USGS will not resume airgun activity until the marine mammal has cleared the EZ, or until the PSVO is confident that the animal has left the vicinity of the vessel. Criteria for judging that the animal has cleared the EZ will be as described in the preceding section.

Ramp-up Procedures—USGS will follow a ramp-up procedure when the airgun array begins operating after a specified period without airgun operations or when a power-down has exceeded that period. USGS proposes that, for the present cruise, this period would be approximately eight min. This period is based on the 180 dB radius (940 m) for the 36 airgun array towed at a depth of 9 m in relation to the minimum planned speed of the *Langseth* while shooting (7.4 km/hr). USGS and L–DEO have used similar periods (approximately 8 to 10 min) during previous L–DEO surveys.

Ramp-up will begin with the smallest airgun in the array (40 in^3). Airguns will be added in a sequence such that the source level of the array will increase in steps not exceeding six dB per five min period over a total duration of approximately 35 min. During ramp-up, the PSOs will monitor the EZ, and if marine mammals are sighted, USGS will implement a power-down or shut-down as though the full airgun array were operational.

If the complete EZ has not been visible for at least 30 min prior to the start of operations in either daylight or nighttime, USGS will not commence the ramp-up unless at least one airgun (40 in^3 or similar) has been operating during the interruption of seismic survey operations. Given these provisions, it is likely that the airgun array will not be ramped-up from a complete shut-down at night or in thick fog, because the outer part of the EZ for that array will not be visible during those conditions. If one airgun has operated during a power-down period, ramp-up to full power will be permissible at night or in poor visibility, on the assumption that marine mammals will be alerted to the approaching seismic vessel by the sounds from the single airgun and could move away. USGS will not initiate a ramp-up of the airguns if a marine mammal is sighted within or near the applicable EZs during the day or close to the vessel at night.

Special Procedures for Situations and Species of Concern—USGS will implement special mitigation procedures as follows:

- The airguns will be shut-down immediately if ESA-listed species for which no takes are being requested (*i.e.,* North Pacific right and blue whales) are sighted at any distance from the vessel. Ramp-up will only begin if the whale has not been seen for 30 min.
- Concentrations of humpback, fin, and/or killer whales will be avoided if possible, and the array will be powered-down if necessary. For purposes of this survey, a concentration or group of whales will consist of three or more individuals visually sighted that do not appear to be traveling (*e.g.,* feeding, socializing, *etc.*).

NMFS has carefully evaluated the applicant's mitigation measures and has considered a range of other measures in the context of ensuring that NMFS prescribes the means of effecting the least practicable adverse impact on the affected marine mammal species and stocks and their habitat. NMFS's evaluation of potential measures included consideration of the following factors in relation to one another:

(1) The manner in which, and the degree to which, the successful implementation of the measure is expected to minimize adverse impacts to marine mammals;

(2) The proven or likely efficacy of the specific measure to minimize adverse impacts as planned; and

(3) The practicability of the measure for applicant implementation.

Based on NMFS's evaluation of the applicant's measures, as well as other measures considered by NMFS or recommended by the public, NMFS has determined that the mitigation measures provide the means of effecting the least practicable adverse impacts on marine mammal species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance.

Monitoring and Reporting

In order to issue an ITA for an activity, section 101(a)(5)(D) of the MMPA states that NMFS must set forth ''requirements pertaining to the monitoring and reporting of such taking.'' The MMPA implementing regulations at 50 CFR 216.104(a)(13) indicate that requests for IHAs must include the suggested means of accomplishing the necessary monitoring and reporting that will result in increased knowledge of the species and of the level of taking or impacts on populations of marine mammals that are expected to be present in the action area.

Monitoring

USGS would sponsor marine mammal monitoring during the present project, in order to implement the mitigation measures that require real-time monitoring, and to satisfy the anticipated monitoring requirements of the IHA. USGS's Monitoring Plan is described below this section. The monitoring work described here has been planned as a self-contained project independent of any other related monitoring projects that may be occurring simultaneously in the same regions. USGS is prepared to discuss coordination of its monitoring program with any related work that might be done by other groups insofar as this is practical and desirable.

Vessel-Based Visual Monitoring

USGS's PSVOs will be based aboard the seismic source vessel and will watch for marine mammals near the vessel during daytime airgun operations and during any ramp-ups at night. PSVOs will also watch for marine mammals near the seismic vessel for at least 30 min prior to the start of airgun operations after an extended shut-down.

PSVOs will conduct observations during daytime periods when the seismic system is not operating for comparison of sighting rates and behavior with and without airgun operations and between acquisition periods. Based on PSVO observations, the airguns will be powered-down or shut-down when marine mammals are observed within or about to enter a designated EZ.

During seismic operations in the central-western Bering Sea, at least four PSOs will be based aboard the *Langseth.* USGS will appoint the PSOs with NMFS's concurrence. Observations will take place during ongoing daytime operations and nighttime ramp-ups of the airguns. During the majority of seismic operations, two PSVOs will be on duty from the observation tower to monitor marine mammals near the seismic vessel. Use of two simultaneous PSVOs will increase the effectiveness of detecting animals near the source vessel. However, during meal times and bathroom breaks, it is sometimes difficult to have two PSVOs on effort, but at least one PSVO will be on duty. PSVO(s) will be on duty in shifts of duration no longer than 4 hr.

Two PSVOs will also be on visual watch during all nighttime ramp-ups of the seismic airguns. A third PSO (*i.e.,* Protected Species Acoustic Observer (PSAO)) will monitor the PAM equipment 24 hours a day to detect vocalizing marine mammals present in the action area. In summary, a typical daytime cruise would have scheduled two PSVOs on duty from the observation tower, and a third PSAO on PAM. Other crew will also be instructed to assist in detecting marine mammals and implementing mitigation requirements (if practical). Before the start of the seismic survey, the crew will be given additional instruction on how to do so.

The *Langseth* is a suitable platform for marine mammal observations. When stationed on the observation platform, the eye level will be approximately 21.5 m (70.5 ft) above sea level, and the PSVO will have a good view around the entire vessel. During daytime, the PSVOs will scan the area around the vessel systematically with reticle binoculars (*e.g.,* 7 x 50 Fujinon), Big-eye binoculars (25 x 150), and with the naked eye. During darkness, NVDs will be available (ITT F500 Series Generation 3 binocular-image intensifier or equivalent), when required. Laser range-finding binoculars (Leica LRF 1200 laser rangefinder or equivalent) will be available to assist with distance estimation. Those are useful in training observers to estimate distances visually, but are generally not useful in measuring distances to animals directly; that is done primarily with the reticles in the binoculars.

When marine mammals are detected within or about to enter the designated EZ, the airguns will immediately be powered-down or shut-down if necessary. The PSVO(s) will continue to maintain watch to determine when the animal(s) are outside the EZ by visual confirmation. Airgun operations will not resume until the animal is confirmed to have left the EZ, or if not observed after 15 min for species with shorter dive durations (small odontocetes and pinnipeds) or 30 min for species with longer dive durations (mysticetes and large odontocetes, including sperm, killer, and beaked whales).

PAM

PAM will complement the visual monitoring program, when practicable. Visual monitoring typically is not effective during periods of poor visibility or at night, and even with good visibility, is unable to detect marine mammals when they are below the surface or beyond visual range.

Besides the three PSVOs, an additional PSAO with primary responsibility for PAM will also be aboard the vessel. USGS can use acoustic monitoring in addition to visual observations to improve detection, identification, and localization of cetaceans. The acoustic monitoring will serve to alert visual observers (if on duty) when vocalizing cetaceans are detected. It is only useful when marine mammals call, but it can be effective either by day or by night, and does not depend on good visibility. It will be monitored in real time so that the PSVOs can be advised when cetaceans are detected. When bearings (primary and mirror-image) to calling cetacean(s) are determined, the bearings will be relayed to the visual observer to help him/her sight the calling animal(s).

The PAM system consists of hardware (*i.e.,* hydrophones) and software. The ''wet end'' of the system consists of a towed hydrophone array that is connected to the vessel by a cable. The array will be deployed from a winch located on the back deck. A deck cable will connect from the winch to the main computer laboratory where the acoustic station and signal conditioning and processing system will be located. The digitized signal and PAM system is monitored by PSAOs at a station in the main laboratory. The lead in from the hydrophone array is approximately 400 m (1,312 ft) long, the active section of the array is approximately 56 m (184 ft) long, and the hydrophone array is typically towed at depths of less than 20 m (66 ft).

Ideally, the PSAO will monitor the towed hydrophones 24 hr per day at the seismic survey area during airgun operations, and during most periods when the *Langseth* is underway while the airguns are not operating. However, PAM may not be possible if damage occurs to both the primary and back-up hydrophone arrays during operations. The primary PAM streamer on the *Langseth* is a digital hydrophone streamer. Should the digital streamer fail, back-up systems should include an analog spare streamer and a hull-mounted hydrophone. Every effort would be made to have a working PAM system during the cruise. In the unlikely event that all three of these systems were to fail, USGS would continue science acquisition with the visual-based observer program. The PAM system is a supplementary enhancement to the visual monitoring program. If weather conditions were to prevent the use of PAM then conditions would also likely prevent the use of the airgun array.

One PSAO will monitor the acoustic detection system at any one time, by listening to the signals from two channels via headphones and/or speakers and watching the real-time spectrographic display for frequency ranges produced by cetaceans. PSAOs monitoring the acoustical data will be on shift for one to six hours at a time. Besides the PSVO, an additional PSAO with primary responsibility for PAM will also be aboard the source vessel. All PSVOs are expected to rotate through the PAM position, although the most experienced with acoustics will be on PAM duty more frequently.

When a vocalization is detected while visual observations are in progress, the PSAO will contact the PSVO immediately, to alert him/her to the presence of cetaceans (if they have not already been seen), and to allow a power-down or shut-down to be initiated, if required. The information regarding the call will be entered into a database. Data entry will include an acoustic encounter identification number, whether it was linked with a visual sighting, date, time when first and last heard and whenever any additional information was recorded, position and water depth when first detected, bearing if determinable, species or species group (*e.g.,* unidentified dolphin, sperm whale), types and nature of sounds heard (*e.g.,* clicks, continuous, sporadic, whistles, creaks, burst pulses, strength of signal, *etc.*), and any other notable information. The acoustic detection can also be recorded for further analysis.

PSVO Data and Documentation

PSVOs will record data to estimate the numbers of marine mammals exposed to various received sound levels and to document apparent disturbance reactions or lack thereof. Data will be used to estimate numbers of animals potentially 'taken' by harassment (as defined in the MMPA). They will also provide information needed to order a power-down or shut-down of the airguns when a marine mammal is within or near the EZ. Observations will also be made during daytime periods when the *Langseth* is underway without seismic operations. In addition to transits to, from, and through the study area, there will also be opportunities to collect baseline biological data during the deployment and recovery of OBSs.

When a sighting is made, the following information about the sighting will be recorded:

(1) Species, group size, age/size/sex categories (if determinable), behavior when first sighted and after initial sighting, heading (if consistent), bearing and distance from seismic vessel, sighting cue, apparent reaction to the airguns or vessel (*e.g.,* none, avoidance, approach, paralleling, *etc.*), and behavioral pace.

(2) Time, location, heading, speed, activity of the vessel, sea state, visibility, and sun glare.

The data listed under (2) will also be recorded at the start and end of each observation watch, and during a watch whenever there is a change in one or more of the variables.

All observations and power-downs or shut-downs will be recorded in a standardized format. Data will be entered into an electronic database. The accuracy of the data entry will be verified by computerized data validity checks as the data are entered and by subsequent manual checking of the database. These procedures will allow initial summaries of data to be prepared during and shortly after the field program, and will facilitate transfer of the data to statistical, graphical, and other programs for further processing and archiving.

Results from the vessel-based observations will provide:

(1) The basis for real-time mitigation (airgun power-down or shut-down).

(2) Information needed to estimate the number of marine mammals potentially taken by harassment, which must be reported to NMFS.

(3) Data on the occurrence, distribution, and activities of marine mammals in the area where the seismic study is conducted.

(4) Information to compare the distance and distribution of marine mammals relative to the source vessel at times with and without seismic activity.

(5) Data on the behavior and movement patterns of marine mammals seen at times with and without seismic activity.

USGS will submit a report to NMFS and NSF within 90 days after the end of the cruise. The report will describe the operations that were conducted and sightings of marine mammals near the operations. The report will provide full documentation of methods, results, and interpretation pertaining to all monitoring. The 90-day report will summarize the dates and locations of seismic operations, and all marine mammal sightings (dates, times, locations, activities, associated seismic survey activities). The report will also include estimates of the number and nature of exposures that could result in ''takes'' of marine mammals by harassment or in other ways.

In the unanticipated event that the specified activity clearly causes the take of a marine mammal in a manner prohibited by this IHA, such as an injury (Level A harassment), serious injury or mortality (*e.g.,* ship-strike, gear interaction, and/or entanglement), USGS will immediately cease the specified activities and immediately report the incident to the Chief of the Permits, Conservation, and Education Division, Office of Protected Resources, NMFS, at 301–427–8401 and/or by e-mail to *Michael.Payne@noaa.gov* and *Brian.D.Hopper@noaa.gov,* and the Alaska Regional Stranding Coordinators (*Aleria.Jensen@noaa.gov* and *Barbara.Mahoney@noaa.gov*). The report must include the following information:

- Time, date, and location (latitude/longitude) of the incident;
- Name and type of vessel involved;
- Vessel's speed during and leading up to the incident;
- Description of the incident;
- Status of all sound source use in the 24 hours preceding the incident;
- Water depth;
- Environmental conditions (*e.g.,* wind speed and direction, Beaufort sea state, cloud cover, and visibility);
- Description of all marine mammal observations in the 24 hours preceding the incident;
- Species identification or description of the animal(s) involved;
- Fate of the animal(s); and
- Photographs or video footage of the animal(s) (if equipment is available).

Activities will not resume until NMFS is able to review the circumstances of the prohibited take. NMFS will work with USGS to determine what is necessary to minimize the likelihood of further prohibited take and ensure MMPA compliance. USGS may not resume their activities until notified by NMFS via letter or e-mail, or telephone.

In the event that USGS discovers an injured or dead marine mammal, and the lead PSO determines that the cause of the injury or death is unknown and the death is relatively recent (*i.e.,* in less than a moderate state of decomposition as described in the next paragraph), USGS will immediately report the incident to the Chief of the Permits, Conservation, and Education Division, Office of Protected Resources, NMFS, at 301–427–8401, and/or by e-mail to *Michael.Payne@noaa.gov* and *Brian.D.Hopper@noaa.gov,* and the NMFS Alaska Stranding Hotline (1–877–925–7773) and/or by e-mail to the Alaska Regional Stranding Coordinators (*Aleria.Jensen@noaa.gov* and *Barbara.Mahoney@noaa.gov*). The report must include the same information identified in the paragraph above. Activities may continue while NMFS reviews the circumstances of the incident. NMFS will work with USGS to determine whether modifications in the activities are appropriate.

In the event that USGS discovers an injured or dead marine mammal, and the lead PSO determines that the injury or death is not associated with or related to the activities authorized in the IHA (*e.g.,* previously wounded animal, carcass with moderate to advanced decomposition, or scavenger damage), USGS will report the incident to the Chief of the Permits, Conservation, and Education Division, Office of Protected Resources, NMFS, at 301–427–8401, and/or by e-mail to *Michael.Payne@noaa.gov* and *Brian.D.Hopper@noaa.gov,* and the NMFS Alaska Stranding Hotline (1–877–925–7773) and/or by e-mail to the Alaska Regional Stranding Coordinators (*Aleria.Jensen@noaa.gov* and *Barbara.Mahoney@noaa.gov*), within 24 hours of the discovery. USGS will provide photographs or video footage (if available) or other documentation of the stranded animal sighting to NMFS and the Marine Mammal Stranding Network.

Estimated Take by Incidental Harassment

Except with respect to certain activities not pertinent here, the MMPA defines ''harassment'' as:

> any act of pursuit, torment, or annoyance which (i) has the potential to injure a marine mammal or marine mammal stock in the wild [Level A harassment]; or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering [Level B harassment].

Only take by Level B harassment is anticipated and authorized as a result of the marine seismic survey in the central-western Bering Sea. Acoustic stimuli (*i.e.,* increased underwater sound) generated during the operation of the seismic airgun array may have the potential to cause marine mammals in the survey area to be exposed to sounds at or greater than 160 dB or cause temporary, short-term changes in behavior. There is no evidence that the planned activities could result in injury, serious injury, or mortality within the specified geographic area for which NMFS has issued the IHA. Take by injury, serious injury, or mortality is thus neither anticipated nor authorized. NMFS has determined that the required mitigation and monitoring measures will minimize any potential risk for injury, serious injury, or mortality.

The following sections describe USGS's methods to estimate take by incidental harassment and present the applicant's estimates of the numbers of marine mammals that could be affected during the seismic program. The estimates are based on a consideration of the number of marine mammals that could be harassed by operations with the 36 airgun array to be used during approximately 2,420 km (1,307 nmi) of survey lines in the central-western Bering Sea.

USGS assumes that, during simultaneous operations of the airgun array and the other sources, any marine mammals close enough to be affected by the MBES and SBP would already be affected by the airguns. However, whether or not the airguns are operating simultaneously with the other sources, marine mammals are expected to exhibit no more than short-term and inconsequential responses to the MBES and SBP given their characteristics (*e.g.,* narrow, downward-directed beam) and other considerations described previously. Such reactions are not considered to constitute ''taking'' (NMFS, 2001). Therefore, USGS provides no additional allowance for animals that could be affected by sound sources other than airguns.

There are no systematic data on the numbers and densities of marine mammals in the deep, offshore waters of the central-western Bering Sea. The closest survey data are from Moore *et al,* (2002), who conducted vessel-based surveys in the Bering Sea during July 5–August 5, 1999 and during June 10–July 3, 2000. The area surveyed extended from the Alaska Peninsula to approximately 58.8° North and was separated into two areas: the central-eastern Bering Sea and the southeastern Bering Sea. Most of the area covered was in water depths greater than 500 m. Similar surveys were conducted during July 17–August 5, 1997 and June 7–July 2, 1999 (Tynan 2004) and during June–July 2002, 2008, and 2010 (Friday *et al.,* 2008, 2011). Most surveys for pinnipeds in Alaskan waters have estimated the number of animals at haulout sites, not in the water (*e.g.,* Loughlin, 1994; Sease *et al.,* 2001; Withrow and Cesarone, 2002; Cease and York, 2003). USGS and NMFS are not aware of any at-sea estimates of pinnipeds in the offshore waters of the Bering Sea.

Table 1 (Table 6 of the IHA application) gives the estimated average (best) and maximum densities of marine mammals expected to occur in the deep, offshore waters of the survey area. For cetaceans, USGS used the densities reported by Moore *et al.* (2002), which were corrected for trackline detection probability, but not availability biases, which was assumed to be 1. In addition, USGS calculated density estimates from the Friday *et al.* (2011) effort and sightings northwest of the Pribilof Islands using correction values from Barlow and Forney (2007). For two species sighted in the southeastern Bering Sea, but not the central-eastern Bering Sea (Baird's beaked whale and Pacific white-sided dolphin), USGS assigned densitities using their best professional judgment. Finally, USGS used seasonal densities for pinnipeds, which were based on counts at haul-out sites and biological (mostly breeding) information to estimate in-water densities.

There is some uncertainty about the representativeness of the data and the assumptions used in the calculations below for two main reasons: (1) The surveys from which cetacean densities were derived were conducted in June–July whereas the seismic survey is in August; and (2) they were in shelf and slope waters, where most marine mammals are expected to occur in much higher densities than in the deep, offshore water of the survey area. However, the densities are based on a considerable survey effort (19,160 km), and the marine mammal surveys and the seismic survey are in the same season; therefore, the approach used here is believed to be the best available approach.

Also, to provide some allowance for these uncertainties, ''maximum estimates'' as well as ''best estimates'' of the densities present and numbers potentially affected have been derived. Best estimates of cetacean density are effort-weighted mean densities from the various surveys, whereas maximum estimates of density come from the individual survey that provided the highest density. For marine mammals where only one density estimate was available, the maximum is 1.5 times the best estimate.

For one species, the Dall's porpoise, density estimates in the original reports are much higher than densities expected during the survey, because this porpoise is attracted to vessels. USGS estimates for Dall's porpoises are from vessel-based surveys without seismic activity; they are overestimates possibly by a factor of 5 times, given the tendency of this species to approach vessels (Turnock and Quinn, 1991). Noise from the airgun array during the survey is expected to at least reduce and possibly eliminate the tendency of this porpoise to approach the vessel. Dall's porpoises are tolerant of small airgun sources (MacLean and Koski, 2005) and tolerated higher sound levels than other species during a large-array survey (Bain and Williams, 2006); however, they did respond to that and another large airgun array by moving away (Calambokidis and Osmek, 1998; Bain and Williams, 2006). Because of the probable overestimates, the best and maximum estimates for Dall's porpoises shown in Table 1 (Table 6 of the IHA application) are one-quarter of the reported densities. In fact, actual densities are probably slightly lower than that.

USGS's estimates of exposures to various sound levels assume that the surveys will be fully completed including the contingency line; in fact, the ensonified areas calculated using the planned number of line-km have been increased by 25 percent to accommodate lines that may need to be repeated, equipment testing, *etc.* As is typical during offshore ship surveys, inclement weather and equipment malfunctions are likely to cause delays and may limit the number of useful line-kilometers of seismic operations that can be undertaken. Furthermore, any marine mammal sightings within or near the designated EZs will result in the power-down or shut-down of seismic operations as a mitigation measure. Thus, the following estimates of the numbers of marine mammals potentially exposed to sound levels of 160 dB re 1 μPa (rms) are precautionary and probably overestimate the actual numbers of marine mammals that might be involved. These estimates also assume that there will be no weather, equipment, or mitigation delays, which is highly unlikely.

USGS estimated the number of different individuals that may be exposed to airgun sounds with received levels greater than or equal to 160 dB re 1 μPa (rms) on one or more occasions by considering the total marine area that would be within the 160 dB radius around the operating airgun array on at least one occasion and the expected density of marine mammals. The number of possible exposures (including repeated exposures of the same individuals) can be estimated by considering the total marine area that would be within the 160 dB radius around the operating airguns, including areas of overlap. In the survey, the seismic lines are widely spaced in the survey area, so few individual marine mammals would be exposed more than once during the survey. The area including overlap is only 1.13 times the area excluding overlap. Moreover, it is unlikely that a particular animal would stay in the area during the entire survey. The number of different individuals potentially exposed to received levels greater than or equal to 160 re 1 μPa was calculated by multiplying:

(1) The expected species density, either ''mean'' (*i.e.,* best estimate) or ''maximum'', times

(2) The anticipated area to be ensonified to that level during airgun operations excluding overlap.

The area expected to be ensonified was determined by entering the planned survey lines into a MapInfo GIS, using the GIS to identify the relevant areas by ''drawing'' the applicable 160 dB buffer (see Table 1 of the IHA application) around each seismic line, and then calculating the total area within the buffers. Areas of overlap (because of lines being closer together than the 160 dB radius) were limited and included only once when estimating the number of individuals exposed. Before calculating numbers of individuals exposed, the areas were increased by 25 percent as a precautionary measure.

Table 1 (Table 6 of the IHA application) shows the best and maximum estimates of the number of different individual marine mammals that potentially could be exposed to greater than or equal to 160 dB re 1 μPa (rms) during the seismic survey if no animals moved away from the survey vessel. The requested take authorization, given in Table 3 (the far right column of Table 4 of the IHA application), is based on the best estimates rather than the maximum estimates of the numbers of individuals exposed, because of uncertainties about the representativeness of the density data discussed previously. For cetacean species not listed under the ESA that could occur in the study area but were not sighted in the surveys from which density estimates were calculated—Baird's beaked whales and Stejneger's beaked whales—the average group size has been used to request take authorization. For ESA-listed cetacean species unlikely to be encountered during the study (*i.e.,* North Pacific right and blue whales), the requested takes are zero.

Applying the approach described above, approximately 12,372 km² (3,607 nmi²) (approximately 15,465 km² (4,509 nmi²) including the 25 percent contingency) would be within the 160 dB isopleths on one or more occasions during the survey, assuming that the contingency line is completed. Because this approach does not allow for turnover in the marine mammal populations in the study area during the course of the survey, the actual number of individuals exposed could be underestimated in some cases. However, the approach assumes that no cetaceans will move away from or toward the trackline as the *Langseth* approaches in response to increasing sound levels prior to the time the levels reach 160 dB, which will result in overestimates for those species known to avoid seismic vessels.

The ''best estimate'' of the number of individual cetaceans that could be exposed to seismic sounds with greater than or equal to 160 dB re 1 μPa (rms) during the survey is 271 (see Table 7 of the IHA application). That total includes 69 whales listed as endangered under the ESA (6 humpback, 1 sei, 61 fin, and 1 sperm whale, which would represent less than 0.03 percent, 0.01 percent, 0.38 percent, and 0.01 percent of the regional populations, respectively. Estimated takes also include five Baird's beaked whales, two Stejneger's beaked whales, 44 killer whales, and 19 minke whales, which would represent 0.02 percent, Not Available (NA), 0.51 percent, and 0.08 percent of the regional populations, respectively. Dall's porpoises are expected to be the most common species in the study area; the best estimate of the number of Dall's porpoises that could be exposed is 137 or 0.01 percent of the regional population. This may be a slight overestimate because the estimated densities are slight overestimates. Estimates for other species are lower. The ''maximum estimates'' total 703 cetaceans. ''Best estimates'' of 42 Steller sea lions, 441 northern fur seals, and 674 ribbon seals could be exposed to airgun sounds with received levels greater than or equal to 160 dB re 1 μPa (rms). These estimates represent 0.06 percent of the Steller sea lion regional population, 0.04 percent of the northern fur seal regional population, and 0.71 percent of the ribbon seal regional population. The estimated numbers of pinnipeds that could be exposed to received levels greater than or equal to 160 dB re 1 μPa (rms) are probably overestimates of the actual numbers that will be affected. During the August survey period, the Steller sea lion is in its breeding season, with males staying on land and females with pups generally staying close to the rookeries in shallow water. Male northern fur seals are at their rookeries in June, and adult females are either there or migrating there, possibly through the survey area. No take has been requested for North Pacific right, bowhead, gray, and blue whales, Cuvier's beaked whales, and white-sided dolphins. In addition, takes were not requested for spotted and ringed seals. Although these marine mammal species may occur in the offshore waters of the Bering Sea in the summer (Table 2), USGS and NMFS believe that the remote likelihood of encountering these species in the survey area (most of which are considered rare to uncommon during the summer) does not warrant requesting and/or authorizing takes.

TABLE 3—ESTIMATES OF THE POSSIBLE NUMBERS OF MARINE MAMMALS EXPOSED TO DIFFERENT SOUND LEVELS ≥ 160 dB DURING USGS'S SEISMIC SURVEY IN THE CENTRAL-WESTERN BERING SEA DURING AUGUST 2011

Species	Estimated number of individuals exposed to sound levels ≥ 160 dB re 1 μPa (Best [1])	Estimated number of individuals exposed to sound levels ≥ 160 dB re 1 μPa (Maximum [1])	Take authorized	Approximate percent of regional population [2] (Best)
Mysticetes:				
North Pacific right whale	0	0	0	0
Bowhead whale	0	0	0	0
Gray whale	0	2	0	<0.01
Humpback whale	6	16	6	0.03
Minke whale	19	63	19	0.08
Sei whale	1	9	1	0.01
Fin whale	61	263	61	0.38
Blue whale	0	0	0	0
Physeteridae:				
Sperm whale	1	2	1	<0.01
Ziphidae:				
Cuvier's beaked whale	0	0	0	0
Baird's beaked whale	1	2	5	0.02
Stejneger's beaked whale	1	2	2	NA
Delphinidae:				
Pacific white-sided dolphin	0	1	0	<0.01
Killer whale	44	61	44	0.51
Phocoenidae:				
Dall's porpoise	137	282	137	0.01
Pinnipeds:				
Northern fur seal	441	661	441	0.04
Steller sea lion	42	63	42	0.06

TABLE 3—ESTIMATES OF THE POSSIBLE NUMBERS OF MARINE MAMMALS EXPOSED TO DIFFERENT SOUND LEVELS ≥ 160 dB DURING USGS'S SEISMIC SURVEY IN THE CENTRAL-WESTERN BERING SEA DURING AUGUST 2011—Continued

Species	Estimated number of individuals exposed to sound levels ≥ 160 dB re 1 μPa (Best [1])	Estimated number of individuals exposed to sound levels ≥ 160 dB re 1 μPa (Maximum [1])	Take authorized	Approximate percent of regional population [2] (Best)
Spotted seal	0	0	0	0
Ringed seal	0	0	0	0
Ribbon seal	674	1011	674	0.71

[1] Best and maximum estimates are based on densities from Table 3 and ensonified areas (including 25% contingency) of 26,166.25 km^2 for 160 dB.
[2] Regional population size estimates are from Table 2 (see Table 2 of the IHA application); NA means not available.

Encouraging and Coordinating Research

USGS will coordinate the planned marine mammal monitoring program associated with the seismic survey in the central-western Bering Sea with other parties that may have an interest in the area and/or be conducting marine mammal studies in the same region during the seismic survey. USGS will coordinate with applicable U.S. agencies (*e.g.,* NMFS), and will comply with their requirements.

Negligible Impact and Small Numbers Analysis and Determination

NMFS has defined ''negligible impact'' in 50 CFR 216.103 as '' * * * an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival.''

In making a negligible impact determination, NMFS evaluated factors such as:

(1) The number of anticipated injuries, serious injuries, or mortalities;

(2) The number, nature, intensity, and duration of Level B harassment (all relatively limited); and

(3) The context in which the takes occur (*i.e.,* impacts to areas of significance, impacts to local populations, and cumulative impacts when taking into account successive/contemporaneous actions when added to baseline data);

(4) The status of stock or species of marine mammals (*i.e.,* depleted, not depleted, decreasing, increasing, stable, and impact relative to the size of the population);

(5) Impacts on habitat affecting rates of recruitment or survival; and

(6) The effectiveness of monitoring and mitigation measures (*i.e.,* the manner and degree in which the measure is likely to reduce adverse impacts to marine mammals, the likely effectiveness of measures, and the practicability of implementation).

For reasons stated previously in this document, and in the proposed notice of an IHA (76 FR 33246, June 8, 2011), the specified activities associated with the marine seismic survey are not likely to cause PTS, or other non-auditory injury, serious injury, or death because:

(1) The likelihood that, given sufficient notice through relatively slow ship speed, marine mammals are expected to move away from a noise source that is annoying prior to its becoming potentially injurious;

(2) The potential for temporary or permanent hearing impairment is very low and would likely be avoided through the incorporation of the monitoring and mitigation measures;

(3) The fact that pinnipeds and cetaceans would have to be closer than 400 m (1,312.3 ft) and 940 m (3,084 ft) in deep water when the 36 airgun array and 12 m (39.4 ft) and 40 m (131.2ft) when the single airgun is in use at 9 m (29.5 ft) tow depth from the vessel to be exposed to levels of sound believed to have even a minimal chance of causing permanent threshold shift; and

(4) The likelihood that marine mammal detection ability by trained PSOs is high at close proximity to the vessel.

No injuries, serious injuries, or mortalities are anticipated to occur as a result of the USGS's planned marine seismic survey, and none are authorized. Only short-term behavioral disturbance is anticipated to occur due to the brief and sporadic duration of the survey activities. Due to the nature, degree, and context of behavioral harassment anticipated, the activity is not expected to impact rates of recruitment or survival for any affected species or stock.

As mentioned previously, NMFS estimates that 12 species of marine mammals under its jurisdiction could be potentially affected by Level B harassment over the course of the IHA. For each species, these numbers are small relative to the population size. NMFS has determined, provided that the aforementioned mitigation and monitoring measures are implemented, that the impact of conducting a marine seismic survey in the central-western Bering Sea, August 2011, may result, at worst, in a temporary modification in behavior and/or low-level physiological effects (Level B harassment) of small numbers of certain species of marine mammals.

While behavioral modifications, including temporarily vacating the area during the operation of the airgun(s), may be made by these species to avoid the resultant acoustic disturbance, the availability of alternate areas within these areas and the short and sporadic duration of the research activities, have led NMFS to determine that this action will have a negligible impact on the species in the specified geographic region.

Based on the analysis contained in this notice of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the mitigation and monitoring measures, NMFS finds that USGS's planned research activities will result in the incidental take of small numbers of marine mammals, by Level B harassment only, and that the total taking from the marine seismic survey will have a negligible impact on the affected species or stocks of marine mammals; and that impacts to affected species or stocks of marine mammals have been mitigated to the lowest level practicable.

Impact on Availability of Affected Species or Stock for Taking for Subsistence Uses

Section 101(a)(5)(D) also requires NMFS to determine that the authorization will not have an unmitigable adverse effect on the availability of marine mammal species or stocks for subsistence use. There are no relevant subsistence uses of marine mammals in the study area (deep, offshore waters of the central-western Bering Sea) that implicate MMPA section 101(a)(5)(D).

Endangered Species Act

Of the species of marine mammals that may occur in the survey area, several are listed as endangered under the ESA, including the North Pacific right, humpback, sei, fin, blue, and sperm whales, as well as the western stock of Steller sea lions. The eastern stock of Steller sea lions is listed as threatened. Under section 7 of the ESA, USGS initiated formal consultation with the NMFS, Office of Protected Resources, Endangered Species Division, on this seismic survey. NMFS's Office of Protected Resources, Permits, Conservation and Education Division, also initiated formal consultation under section 7 of the ESA with NMFS's Office of Protected Resources, Endangered Species Division, to obtain a Biological Opinion (BiOp) evaluating the effects of issuing the IHA on threatened and endangered marine mammals and, if appropriate, authorizing incidental take. In August 2011, NMFS issued a BiOp and concluded that the action and issuance of the IHA are not likely to jeopardize the continued existence of the North Pacific right, humpback, sei, fin, blue, and sperm whales, and Steller sea lions. The BiOp also concluded that designated critical habitat for these species does not occur in the action area and would not be affected by the survey. USGS must comply with the Relevant Terms and Conditions of the Incidental Take Statement (ITS) corresponding to NMFS's BiOp issued to both USGS and NMFS's Office of Protected Resources. USGS must also comply with the mitigation and monitoring requirements included in the IHA in order to be exempt under the ITS in the BiOp from the prohibition on take of listed endangered marine mammal species otherwise prohibited by section 9 of the ESA.

NEPA

With its complete application, USGS provided NMFS an EA analyzing the direct, indirect, and cumulative environmental impacts of the specified activities on marine mammals including those listed as threatened or endangered under the ESA. The EA, prepared by LGL on behalf of USGS, is entitled ''Environmental Assessment of a Marine Geophysical Survey by the R/V *Marcus G. Langseth* in the central-western Bering Sea, August 2011.'' After NMFS reviewed and evaluated the USGS EA for consistency with the regulations published by the Council of Environmental Quality (CEQ) and NOAA Administrative Order 216–6, Environmental Review Procedures for Implementing the National Environmental Policy Act, NMFS adopted the USGS EA and issued a Finding of No Significant Impact (FONSI).

Authorization

NMFS has issued an IHA to USGS for the take, by Level B harassment, of small numbers of marine mammals incidental to conducting a marine geophysical survey in the central-western Bering Sea, August 2011, provided the previously mentioned mitigation, monitoring, and reporting requirements are incorporated.

Dated: August 5, 2011.

James H. Lecky,

Director, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2011–20461 Filed 8–10–11; 8:45 am]

BILLING CODE 3510–22–P

CONSUMER PRODUCT SAFETY COMMISSION

[CPSC Docket No. 11–C0009]

Perfect Fitness, Provisional Acceptance of a Settlement Agreement and Order

AGENCY: Consumer Product Safety Commission.

ACTION: Notice.

SUMMARY: It is the policy of the Commission to publish settlements which it provisionally accepts under the Consumer Product Safety Act in the **Federal Register** in accordance with the terms of 16 CFR 1118.20(e). Published below is a provisionally-accepted Settlement Agreement with Perfect Fitness, containing a civil penalty of $425,000.00.

DATES: Any interested person may ask the Commission not to accept this agreement or otherwise comment on its contents by filing a written request with the Office of the Secretary by August 26, 2011.

ADDRESSES: Persons wishing to comment on this Settlement Agreement should send written comments to the Comment 11–C0009, Office of the Secretary, Consumer Product Safety Commission, 4330 East West Highway, Room 820, Bethesda, Maryland 20814–4408.

FOR FURTHER INFORMATION CONTACT: Jennifer C. Argabright, Trial Attorney, Division of Compliance, Office of the General Counsel, Consumer Product Safety Commission, 4330 East West Highway, Bethesda, Maryland 20814–4408; telephone (301) 504–7808.

SUPPLEMENTARY INFORMATION: The text of the Agreement and Order appears below.

Dated: August 8, 2011.

Todd A. Stevenson,

Secretary.

United States of America Consumer Product Safety Commission

Settlement Agreement

1. In accordance with 16 CFR 1118.20, Perfect Fitness and staff (''Staff'') of the United States Consumer Product Safety Commission (''Commission'') hereby enter into this Settlement Agreement (''Agreement'') under the Consumer Product Safety Act (''CPSA''). The Agreement and the incorporated attached Order resolve Staff's allegations set forth below.

The Parties

2. Staff is the staff of the Commission, an independent federal regulatory agency established pursuant to, and responsible for, the enforcement of the CPSA, 15 U.S.C. 2051–2089.

3. Perfect Fitness is a privately-held Limited Liability Company, organized and existing under the laws of the State of California, with its principal corporate office located at 1750 Bridgeway, Suite A100, Sausalito, California 94965.

Staff Allegations

4. Between January 2008 and August 2008, Perfect Fitness manufactured and distributed approximately ten thousand (10,000) ''Perfect Pullup'' exercise equipment (''Subject Products''). Retailers continued to sell the Subject Products until they were recalled on February 17, 2011. The Subject Products sold for approximately $80–$100 through major sporting goods stores, online retailers, and through direct television marketing.

5. The Subject Products are ''consumer products'' and, at all relevant times, Perfect Fitness was a ''manufacturer'' of these consumer products, which were ''distribute[d] in commerce,'' as those terms are defined or used in sections 3(a)(5), (8), and (11) of the CPSA, 15 U.S.C. 2052(a)(5), (8), and (11).

6. The Subject Products are defective because the handle can break during use, resulting in consumers falling to the floor.

7. Perfect Fitness received its first complaint involving handle breakage in

May 2008. In response, Perfect Fitness initiated an internal review. The internal review revealed that an unusual number of purchasers were returning or requesting replacement Subject Products. Some purchasers of the returned products indicated that the handles had broken during use.

8. In June 2008, Perfect Fitness began re-testing the handle design. The firm preliminarily concluded that the handle design was defective because the material used to make the handles was not strong enough to withstand the pressure load needed to perform properly.

9. In July 2008, Perfect Fitness redesigned the Subject Products in an effort to correct the design defect.

10. By August 2008, Perfect Fitness received additional confirmation through a testing agency that the original design would experience handle failure at an average load of 158.3 pounds. The testing agency additionally confirmed that the redesigned handles would be able to withstand a higher pressure load without handle breakage.

11. On August 1, 2008, Perfect Fitness began production of the redesigned Subject Product, and discontinued distribution of the Subject Products without notifying the Commission of the problems associated with handle breakage.

12. By the end of August 2008, Perfect Fitness received at least eleven (11) more reports of handles breaking, resulting in injuries to consumers.

13. On March 30, 2010, Perfect Fitness posted a notice on its Web site indicating that consumers could replace the Subject Products free of charge. In communications with consumers, representatives of Perfect Fitness represented that the original handles were ''inferior'' and could result in an ''accident.'' By this date, Perfect Fitness was aware of at least twenty-three (23) incidents of handle breakage causing injury.

14. Despite knowledge of the information set forth in paragraphs 5–13, Perfect Fitness did not report to the Commission until December 20, 2010. By that time, Perfect Fitness was aware of at least forty-five (45) specific complaints of injury due to handle breakage and had received over two thousand (2,000) requests for replacement of the Subject Product.

15. Although Perfect Fitness had obtained sufficient information to reasonably support the conclusion that the Subject Product contained a defect which could create a substantial product hazard, or created an unreasonable risk of serious injury or death, Perfect Fitness failed to inform the Commission immediately of such defect or risk, as required by sections 15(b)(3) and (4) of the CPSA, 15 U.S.C. § 2064(b)(3) and (4). In failing to inform the Commission immediately of the defect or advising that the defect involved the Subject Product, Perfect Fitness knowingly violated section 19(a)(4) of the CPSA, 15 U.S.C. 2068(a)(4), as the term ''knowingly'' is defined in section 20(d) of the CPSA, 15 U.S.C. 2069(d).

16. Pursuant to section 20 of the CPSA, 15 U.S.C. 2069, Perfect Fitness is subject to civil penalties for its knowing failure to report, as required under section 15(b) of the CPSA, 15 U.S.C. 2064(b).

Response of Perfect Fitness

17. Perfect Fitness denies the allegations of Staff that the Subject Products contain a defect which could create a substantial product hazard or create an unreasonable risk of serious injury or death, and denies that it knowingly violated the reporting requirements of Section 15(b) of the CPSA, 15 U.S.C. 2064(b).

Agreement of the Parties

18. Under the CPSA, the Commission has jurisdiction over this matter and over Perfect Fitness.

19. In settlement of Staff's allegations, Perfect Fitness shall pay a civil penalty in the amount of four hundred twenty-five thousand dollars ($425,000.00) within twenty (20) calendar days of receiving service of the Commission's final Order accepting the Agreement. The payment shall be made electronically to the CPSC via *http://www.pay.gov.*

20. The parties enter into this Agreement for settlement purposes only. The Agreement does not constitute an admission by Perfect Fitness or a determination by the Commission that Perfect Fitness violated the CPSA's reporting requirements.

21. Upon provisional acceptance of the Agreement by the Commission, the Agreement shall be placed on the public record and published in the **Federal Register** in accordance with the procedures set forth in 16 CFR 1118.20(e). If the Commission does not receive any written request not to accept the Agreement within fifteen (15) calendar days, the Agreement shall be deemed finally accepted on the 16th calendar day after the date it is published in the **Federal Register,** in accordance with 16 CFR 1118.20(f).

22. Upon the Commission's final acceptance of the Agreement and issuance of the final Order, Perfect Fitness knowingly, voluntarily, and completely waives any rights it may have in this matter to the following: (a) An administrative or judicial hearing; (b) judicial review or other challenge or contest of the Commission's actions; (c) a determination by the Commission of whether Perfect Fitness failed to comply with the CPSA and the underlying regulations; (d) a statement of findings of fact and conclusions of law; and (e) any claims under the Equal Access to Justice Act.

23. The Commission may publicize the terms of the Agreement and the Order.

24. The Agreement and the Order shall apply to, and be binding upon, Perfect Fitness and each of its successors and/or assigns until the obligations described in Paragraph 19 have been fulfilled to the satisfaction of the Commission.

25. The Commission issues the Order under the provisions of the CPSA, and a violation of the Order may subject Perfect Fitness and each of its successors and/or assigns to appropriate legal action until the obligations described in Paragraph 19 have been fulfilled to the satisfaction of the Commission.

26. The Agreement may be used in interpreting the Order. Understandings, agreements, representations, or interpretations apart from those contained in the Agreement and the Order may not be used to vary or contradict the terms or the Agreement and the Order. The Agreement shall not be waived, amended, modified, or otherwise altered without written agreement thereto, executed by the party against whom such waiver, amendment, modification, or alteration is sought to be enforced.

27. If any provision of the Agreement or the Order is held to be illegal, invalid, or unenforceable under present or future laws effective during the terms of the Agreement and the Order, such provision shall be fully severable. The balance of the Agreement and the Order shall remain in full force and effect, unless the Commission and Perfect Fitness agree that severing the provision materially affects the purpose of the Agreement and Order.

Perfect Fitness LLC

Dated: *July 28, 2011*

By: ____________________

Alden Mills, *Chief Executive Officer*
Perfect Fitness
1750 Bridgeway
Suite A100
Sausalito, California 94965

Dated: *July 28, 2011*

By: ____________________

Mark Friedman, *President*

Perfect Fitness
1750 Bridgeway
Suite A100
Sausalito, California 94965

Dated: *July 29, 2011*

By: ______________________________

Paul Rubin, Esq.
Patton Boggs LLP
2550 M Street, NW.,
Washington, DC 20037
Counsel for Perfect Fitness

U.S. CONSUMER PRODUCT SAFETY COMMISSION STAFF

Cheryl A. Falvey, *General Counsel*

Mary B. Murphy, *Assistant General Counsel*

Dated: *August 4, 2011*

By: ______________________________

Jennifer C. Argabright, *Trial Attorney*
Division of Compliance
Office of the General Counsel

United States of America

Consumer Product Safety Commission

Order

Upon consideration of the Settlement Agreement entered into between Perfect Fitness and the U.S. Consumer Product Safety Commission (''Commission'') staff, and the Commission having jurisdiction over the subject matter and over Perfect Fitness, and it appearing that the Settlement Agreement and the Order are in the public interest, it is

Ordered that the Settlement Agreement be, and is, hereby, accepted; and it is

Further ordered, that Perfect Fitness shall pay a civil penalty in the amount of four hundred and twenty-five thousand dollars ($425,000.00) within twenty (20) days of service of the Commission's final Order accepting the Settlement Agreement upon counsel for Perfect Fitness identified in the Settlement Agreement. The payment shall be made electronically to the CPSC via *http://www.pay.gov.* Upon the failure of Perfect Fitness to make the foregoing payment when due, interest on the unpaid amount shall accrue and be paid by Perfect Fitness at the federal legal rate of interest set forth at 28 U.S.C. 1961(a) and (b).

Provisionally accepted and provisional Order issued on the *8th* day of *August,* 2011.

By Order of the Commission.

Todd A. Stevenson, *Secretary*
U.S. Consumer Product Safety Commission

[FR Doc. 2011–20463 Filed 8–10–11; 8:45 am]

BILLING CODE 6355–01–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Strategic Environmental Research and Development Program Scientific Advisory Board Meeting

AGENCY: Department of Defense.

ACTION: Notice.

SUMMARY: This Notice is published in accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463). The topic of the meeting on October 12–13, 2011 is to review new start research and development projects requesting Strategic Environmental Research and Development Program (SERDP) funds in excess of $1M. This meeting is open to the public. Any interested person may attend, appear before, or file statements with the Scientific Advisory Board at the time and in the manner permitted by the Board.

DATES: Wednesday, October 12, 2011 from 9 a.m. to 5 p.m. & Thursday, October 13, from 9 a.m. to 5 p.m.

ADDRESSES: SERDP Office Conference Center, 901 North Stuart Street, Suite 804, Arlington, VA 22203.

FOR FURTHER INFORMATION CONTACT: Mr. Jonathan Bunger, SERDP Office, 901 North Stuart Street, Suite 303, Arlington, VA or by telephone at (703) 696–2126.

Dated: August 8, 2011.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2011–20398 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID DOD–2011–OS–0089]

Privacy Act of 1974; System of Records

AGENCY: Office of the Secretary, Department of Defense.

ACTION: Notice to alter a system of records.

SUMMARY: The Office of the Secretary of Defense proposes to alter a system of records in its inventory of record systems subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended.

DATES: This proposed action would be effective without further notice on September 9, 2011 unless comments are received which result in a contrary determination.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

- *Federal Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Federal Docket Management System Office, 1160 Defense Pentagon, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ms. Cindy Allard, Chief, OSD/JS Privacy Office, Freedom of Information Directorate, Washington Headquarters Services, 1155 Defense Pentagon, Washington, DC 20301–1155, or by phone at (703) 588–6830.

SUPPLEMENTARY INFORMATION: The Office of the Secretary of Defense notices for systems of records subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended, have been published in the **Federal Register** and are available from the address in **FOR FURTHER INFORMATION CONTACT.**

The proposed system report, as required by 5 U.S.C. 552a(r) of the Privacy Act of 1974, as amended, was submitted on August 5, 2011, to the House Committee on Oversight and Government Reform, the Senate Committee on Governmental Affairs, and the Office of Management and Budget (OMB) pursuant to paragraph 4c of Appendix I to OMB Circular No. A–130, ''Federal Agency Responsibilities for Maintaining Records About Individuals,'' dated February 8, 1996 (February 20, 1996, 61 FR 6427).

Dated: August 5, 2011.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

DHA 14

SYSTEM NAME:

Computer/Electronics Accommodations Program for People with Disabilities (June 21, 2006, 71 FR 35632).

CHANGES:

* * * * *

SYSTEM NAME:

Delete entry and replace with ''Computer/Electronic Accommodations Program.''

SYSTEM LOCATION:

Delete entry and replace with ''Computer/Electronic Accommodations Program, Skyline 5, Suite 302, 5111 Leesburg Pike, Falls Church, VA 22041–3891.''

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Delete entry and replace with ''All Federal employees and members of the Armed Forces with disabilities that can be addressed with assistive technology solutions.''

CATEGORIES OF RECORDS IN THE SYSTEM:

Delete entry and replace with ''Information includes employee name, grade level, occupational series, prior assistive technology solutions provided to the individual, work email, work address, work telephone number, Federal Agency, computer/electronic accommodations program request number, disability data, history of accommodations being sought and their disposition, and other documentation used in support of the request for an assistive technology solution. Product and vendor contact information includes orders, invoices, declination, and cancellation data for the product and identification of vendors, vendor products used, and product costs.''

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

Delete entry and replace with ''10 U.S.C. 1582, Assistive technology, assistive technology devices, and assistive technology services; 29 U.S.C. 794d, Electronic and information technology; 42 U.S.C. Chapter 126, Equal Opportunity For Individuals With Disabilities; and DoD Instruction 6025.22, Assistive Technology (AT) for Wounded Service Members.''

PURPOSE(S):

Delete entry and replace with ''To administer the Computer/Electronic Accommodations Program, a centrally funded program that provides assistive (computer/electronic) technology solutions to individuals with hearing, visual, dexterity, cognitive, and/or communications impairments in the form of an accessible work environment. The system documents and tracks provided computer/electronic accommodations. May also be used as a management tool for statistical analysis, tracking, reporting, evaluating program effectiveness and conducting research.''

* * * * *

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Delete entry and replace with ''Paper file folders and electronic storage media.''

RETRIEVABILITY:

Delete entry and replace with ''Records are retrieved by employee name, Federal Agency, computer/electronic accommodations program request number, work address, work telephone number.''

SAFEGUARDS:

Delete entry and replace with ''Records are maintained in controlled areas accessible only to authorized DoD personnel. Access to personal information is further restricted by the use of Common Access Card and user ID/passwords. Paper records are maintained in a controlled facility where physical entry is restricted by the use of locks, guards, or administrative procedures. All records are maintained by the DoD.''

RETENTION AND DISPOSAL:

Delete entry and replace with ''Case files are destroyed three (3) years after employee separation from the agency or all appeals are concluded, whichever is later.''

SYSTEM MANAGER(S) AND ADDRESS:

Delete entry and replace with ''Senior Program Manager, Computer/Electronic Accommodations Program, Skyline 5, Suite 810, 5111 Leesburg Pike, Falls Church, VA 22041–3891.''

NOTIFICATION PROCEDURE:

Delete entry and replace with ''Individuals seeking access to information about themselves contained in this system of records should address written inquiries to TRICARE Management Activity, Department of Defense, ATTN: TMA Privacy Officer, Skyline 5, Suite 810, 5111 Leesburg Pike, Falls Church, VA 22041–3206.

Request should contain name, work address, work telephone number, and type of disability.''

RECORD ACCESS PROCEDURES:

Delete entry and replace with ''Individuals seeking access to records about themselves contained in this system should address written inquiries to TRICARE Management Activity, Attention: Freedom of Information Act Requester Service Center, 16401 East Centretech Parkway, Aurora, CO 80011–9066.

Request should contain full name, Federal Agency, computer/electronic accommodations request number, work address, work telephone number, the name and number of this system of records notice, and be signed.''

CONTESTING RECORD PROCEDURES:

The OSD rules for accessing records, for contesting contents, and appealing initial agency determinations are published in OSD Administrative Instruction 81; 32 CFR Part 311, or may be obtained from the system manager.

RECORD SOURCE CATEGORIES:

Delete entry and replace with ''Information provided by the individual and human resources databases maintained by DoD and the Federal Government agencies participating in the Computer/Electronic Accommodations Program.''

* * * * *

DHA 14

SYSTEM NAME:

Computer/Electronic Accommodations Program.

SYSTEM LOCATION:

Computer/Electronic Accommodations Program, Skyline 5, Suite 302, 5111 Leesburg Pike, Falls Church, VA 22041–3891.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

All Federal employees and members of the Armed Forces with disabilities that can be addressed with assistive technology solutions.

CATEGORIES OF RECORDS IN THE SYSTEM:

Information includes employee name, grade level, occupational series, prior assistive technology solutions provided to the individual, work email, work address, work telephone number, Federal Agency, computer/electronic accommodations program request number, disability data, history of accommodations being sought and their disposition, and other documentation used in support of the request for an assistive technology solution. Product and vendor contact information includes orders, invoices, declination, and cancellation data for the product and identification of vendors, vendor products used, and product costs.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

10 U.S.C. 1582, Assistive technology, assistive technology devices, and assistive technology services; 29 U.S.C. 794d, Electronic and information technology; 42 U.S.C. Chapter 126, Equal Opportunity For Individuals With Disabilities; and DoD Instruction 6025.22, Assistive Technology (AT) for Wounded Service Members.

PURPOSE(S):

To administer the Computer/Electronic Accommodations Program, a centrally funded program that provides assistive (computer/electronic) technology solutions to individuals with hearing, visual, dexterity, cognitive, and/or communications impairments in the form of an accessible work environment. The system documents and tracks provided computer/electronic accommodations. May also be used as a management tool for statistical analysis, tracking, reporting, evaluating program effectiveness and conducting research.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act of 1974, as amended, these records may specifically be disclosed outside the DoD as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

To Federal Government agencies participating in the Computer/Electronic Accommodations Program for purposes of providing information as necessary to permit the agency to carry out its responsibilities under the program.

To commercial vendors for purposes of providing information to permit the vendor to identify and provide assistive technology solutions for individuals with disabilities.

The DoD 'Blanket Routine Uses' set forth at the beginning of the Office of the Secretary of Defense (OSD) compilation of systems of records notices apply to this system.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Paper file folders and electronic storage media.

RETRIEVABILITY:

Records are retrieved by employee name, Federal Agency, computer/electronic accommodations program request number, work address, work telephone number.

SAFEGUARDS:

Records are maintained in controlled areas accessible only to authorized DoD personnel. Access to personal information is further restricted by the use of Common Access Card and user ID/passwords. Paper records are maintained in a controlled facility where physical entry is restricted by the use of locks, guards, or administrative procedures. All records are maintained by the DoD.

RETENTION AND DISPOSAL:

Case files are destroyed three (3) years after employee separation from the agency or all appeals are concluded, whichever is later.

SYSTEM MANAGER(S) AND ADDRESS:

Senior Program Manager, Computer/Electronic Accommodations Program, Skyline 5, Suite 810, 5111 Leesburg Pike, Falls Church, VA 22041–3891.

NOTIFICATION PROCEDURE:

Individuals seeking access to information about themselves contained in this system of records should address written inquiries to TRICARE Management Activity, Department of Defense, ATTN: TMA Privacy Officer, Skyline 5, Suite 810, 5111 Leesburg Pike, Falls Church, VA 22041–3206.

Request should contain name, work address, work telephone number, and type of disability.

RECORD ACCESS PROCEDURES:

Individuals seeking access to records about themselves contained in this system should address written inquiries to TRICARE Management Activity, Attention: Freedom of Information Act Requester Service Center, 16401 East Centretech Parkway, Aurora, CO 80011–9066.

Request should contain full name, Federal Agency, computer/electronic accommodations request number, work address, work telephone number, the name and number of this system of records notice, and be signed.

CONTESTING RECORD PROCEDURES:

The OSD rules for accessing records, for contesting contents, and appealing initial agency determinations are published in OSD Administrative Instruction 81; 32 CFR Part 311, or may be obtained from the system manager.

RECORD SOURCE CATEGORIES:

Information provided by the individual and human resources databases maintained by DoD and the Federal Government agencies participating in the Computer/Electronic Accommodations Program.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

[FR Doc. 2011–20345 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Revision to the Standard Forms 76, 76A, 186, and 186A

AGENCY: Under Secretary of Defense for Personnel and Readiness, Federal Voting Assistance Program, Department of Defense.

ACTION: Notice.

SUMMARY: The Department of Defense, Under Secretary of Defense (Personnel and Readiness), Federal Voting Assistance Program, revised the SF 76, Federal Post Card Application (FPCA), SF 76A, Federal Post Card Application (Electronic), SF 186, Federal Write-in Absentee Ballot (FWAB), and SF 186A, Federal Write-in Absentee Ballot (Electronic), to meet Federal laws and technology, including but not limited to, the use of electronic transmission for transmitting the form. The form will be stocked by GSA, Federal Acquisition Service, Inventory Management Branch (QSDLBAB), 819 Taylor Street, Fort Worth, TX 76102–0000 and available November 1, 2011.

DATES: Effective upon publication in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Mr. John Godley, Department of Defense, 703–588–8108.

Dated: August 8, 2011.

Aaron Siegel, Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2011–20421 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Department of the Navy

[Docket ID USN–2011–0014]

Privacy Act of 1974; System of Records

AGENCY: Department of the Navy, Department of Defense (DoD).

ACTION: Notice to Add a New System of Records.

SUMMARY: The Department of the Navy proposes to add a new system of records to its inventory of record systems subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended.

DATES: The changes will be effective on September 12, 2011 unless comments are received that would result in a contrary determination.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

* *Federal Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

* *Mail:* Federal Docket Management System Office, 1160 Defense Pentagon, Washington, DC 20301–1160.

Instructions: All submissions received must include the agency name and docket number for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ms. Robin Patterson, Head, FOIA/Privacy Act Policy Branch, Acting, the Department of the Navy, 2000 Navy Pentagon, Washington, DC 20350–2000, or by phone at (202) 685–6545.

SUPPLEMENTARY INFORMATION: The Department of the Navy systems of records notice subject to the Privacy Act of 1974, (5 U.S.C. 552a), as amended, has been published in the **Federal Register** and is available from the address in **FOR FURTHER INFORMATION CONTACT**.

The proposed systems reports, as required by 5 U.S.C. 552a(r) of the Privacy Act of 1974, as amended, were submitted on August 5, 2011, to the House Committee on Government Report, the Senate Committee on Homeland Security and Governmental Affairs, and the Office of Management and Budget (OMB) pursuant to paragraph 4c of Appendix I to OMB Circular No. A–130, ''Federal Agency Responsibilities for Maintaining records About Individual,'' dated February 8, 1996 (February 20, 1996, 61 FR 6427).

Dated: August 5, 2011.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

NM03760–5

SYSTEM NAME:

DON Military Flight Operations Quality Assurance

SYSTEM LOCATION:

Primary databases (Enterprise Level Servers) are maintained at the Naval Air Systems Command (PMA–209), 47014 Hinkle Circle, Bldg. 420A, Patuxent River, MD 20670.

Secondary databases (COOP) are maintained at 46610 Expedition Drive, Suite 201, Lexington Park, MD 20653.

Local databases (Site Level Servers) are maintained at Navy and Marine Corps aviation activities and select ships. Official mailing addresses are published in the Standard Navy Distribution List.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

All aeronautically designated commissioned Navy and Marine Corps officers and enlisted members assigned as aircrew members in the operation of an aircraft.

CATEGORIES OF RECORDS IN THE SYSTEM:

Name, last four of Social Security Number (SSN), squadron ID; reports of each flight; unique system ID; age and gender (if available); and Common Access Card (CAC) Electronic Data Interchange Personal Identifier (EDIPI) (DoD ID Number). The system will contain ''last four of SSN'' for older records but the Social Security Number (SSN) will no longer be collected/solicited and will be phased out of the system as they meet their retention dates.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

10 U.S.C. 5013, Secretary of the Navy; 10 U.S.C. 5041, Headquarters, Marine Corps; USD–P&R and USD–ATL MFOQA Directive Type Memorandum, Process Implementation memo, October 11, 2005; and E.O. 9397 (SSN), as amended.

PURPOSE(S):

To track pilot and aircrew performance during flights in order to preemptively identify hazards before they lead to mishaps; and provide timely, tangible information on aircrew and system performance for each aircraft flight to prevent mishaps and improve operational readiness.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act of 1974, these records contained therein may specifically be disclosed outside the DoD as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

The DoD 'Blanket Routine Uses' that appear at the beginning of the Navy's compilation of systems of records notices apply to this system.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Electronic storage media.

RETRIEVABILITY:

Unique system ID.

SAFEGUARDS:

System access will be restricted by the use of access controls, Common Access Cards and encryption. Any personal data will be accessed only by users with uniquely assigned roles and permissions and a need to know.

RETENTION AND DISPOSAL:

Personally Identifiable Information is purged from local database electronic records after 90 days. Routine Operations and Training Flights records are cut off annually in November and retired to the nearest Federal Records Center (FRC). Records are destroyed when 7 years old. Units being decommissioned retire files to FRC upon decommissioning.

SYSTEM MANAGER(S) AND ADDRESS:

Commander, Naval Air Systems Command (PMA–209), 47123 Buse Road, Patuxent River, MD 20670–1537.

NOTIFICATION PROCEDURE:

Individuals seeking to determine whether information about themselves that is contained in this system should query the data base at the installation where assigned or address written inquiries to the Commander, Naval Air Systems Command (PMA–209), 47123 Buse Road, Patuxent River, MD 20670–1537.

The signed written request should contain the individual's full name and unique system ID.

The system manager may require an original signature or a notarized signature as a means of proving the identity of the individual requesting access to the records.

RECORD ACCESS PROCEDURES:

Individuals seeking access to information about themselves is contained in this system should query the data base at the installation where assigned or address written inquiries to the Commander, Naval Air Systems Command (PMA–209), 47123 Buse Road, Patuxent River, MD 20670–0000.

The signed written request should contain the individual's full name and unique system ID.

The system manager may require an original signature or a notarized signature as a means of proving the identity of the individual requesting access to the records.

CONTESTING RECORD PROCEDURES:

The Navy's rules for accessing records, and for contesting contents and appealing initial agency determinations are published in Secretary of the Navy Instruction 5211.5; 32 CFR part 701; or may be obtained from the system manager.

RECORD SOURCE CATEGORIES:

Individual and command supported aircrew information systems.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

[FR Doc. 2011–20362 Filed 8–10–11; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF ENERGY

Fusion Energy Sciences Advisory Committee

AGENCY: Office of Science, Department of Energy.

ACTION: Notice of Renewal.

SUMMARY: Pursuant to Section 14(a)(2)(A) of the Federal Advisory Committee Act (Pub. L. 92–463), and in accordance with Title 41 of the Code of Federal Regulations, Section 102–3.65(a), and following consultation with the Committee Management Secretariat, General Services Administration, notice is hereby given that the Fusion Energy Sciences Advisory Committee will be renewed for a two-year period beginning on August 5, 2011.

The Committee provides advice and recommendations to the Department of Energy on long-range plans, priorities, and strategies for advancing plasma science, fusion science, and fusion technology related to the Fusion Energy Sciences program.

Additionally, the renewal of the Fusion Energy Sciences Advisory Committee has been determined to be essential to conduct Department of Energy business, and to be in the public interest in connection with the performance of duties imposed upon the Department of Energy by law and agreement. The Committee will continue to operate in accordance with the provisions of the Federal Advisory Committee Act, and the rules and regulations in implementation of that Act.

FOR FURTHER INFORMATION CONTACT: Mr. Albert Opdenaker, Designated Federal Officer, at (301) 903–4927.

Issued at Washington, DC on August 5, 2011.

Carol A. Matthews,

Committee Management Officer.

[FR Doc. 2011–20402 Filed 8–10–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Portsmouth

AGENCY: Department of Energy (DOE).

ACTION: Notice of Open Meeting.

SUMMARY: This notice announces a meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Portsmouth. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Thursday, September 1, 2011, 6 p.m.

ADDRESSES: Ohio State University, Endeavor Center, 1862 Shyville Road, Piketon, Ohio 45661.

FOR FURTHER INFORMATION CONTACT: Joel Bradburne, Deputy Designated Federal Officer, Department of Energy Portsmouth/Paducah Project Office, Post Office Box 700, Piketon, Ohio 45661, (740) 897–3822, *Joel.Bradburne@lex.doe.gov.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to make recommendations to DOE–EM and site management in the areas of environmental restoration, waste management and related activities.

Tentative Agenda

- Call to Order, Introductions, Review of Agenda.
- Approval of July Minutes.
- Deputy Designated Federal Officer's Comments.
- Federal Coordinator's Comments.
- Liaisons' Comments.
- FLUOR B&W Community Commitment Plan Update, Jerry Schneider.
- Administrative Issues:
  - Subcommittee Updates.
- Motions.
  - Second Reading of the amendment to the Operating Procedures: Section VI. Board Structure C3a. fourteen days changed to seven days as proposed by the Executive Committee.
- Public Comments.
- Final Comments.
- Adjourn.

Public Participation: The meeting is open to the public. The EM SSAB, Portsmouth, welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Joel Bradburne at least seven days in advance of the meeting at the phone number listed above. Written statements may be filed with the Board either before or after the meeting. Individuals who wish to make oral statements pertaining to agenda items should contact Joel Bradburne at the address or telephone number listed above. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to make public comments will be provided a maximum of five minutes to present their comments.

Minutes: Minutes will be available by writing or calling Joel Bradburne at the address and phone number listed above. Minutes will also be available at the following Web site: *http://www.ports-ssab.energy.gov/*.

Issued at Washington, DC on August 4, 2011.

LaTanya R. Butler,

Acting Deputy Committee Management Officer.

[FR Doc. 2011–20403 Filed 8–10–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Energy Information Administration

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: U.S. Energy Information Administration (EIA), Department of Energy (DOE).

ACTION: Agency Information Collection Activities: Proposed Collection; Comment Request.

SUMMARY: The EIA is soliciting comments on the proposed new Form EIA–111, ''Quarterly Electricity Imports and Exports Report.'' This new form would supersede the existing Form OE–781R, ''Monthly Electricity Imports and Exports Report''. The Form OE–781R is currently suspended and would be terminated with the implementation of the proposed Form EIA–111.

DATES: Comments must be filed by October 11, 2011. If you anticipate difficulty in submitting comments within that period, contact the person listed below as soon as possible.

ADDRESSES: Send comments to Michelle Bowles. To ensure receipt of the comments by the due date, e-mail (*eia-111@eia.gov*) is recommended. The mailing address is the U.S. Department of Energy, U.S. Energy Information Administration, *Mail Stop:* EI–23 (Form EIA–111), 1000 Independence Avenue, SW., Washington, DC 20585. Alternatively, Ms. Bowles may be contacted by telephone at 202–586–2430 or via fax at (202) 287–1960.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of any forms and instructions (the draft proposed collection) should be directed to Michelle Bowles at the address listed above. Forms and instructions are also available on the Internet at: *http://beta.eia.gov/survey/form-eia111/proposed.pdf.*

SUPPLEMENTARY INFORMATION:

I. Background
II. Current Actions
III. Request for Comments

I. Background

The Federal Energy Administration Act of 1974 (15 U.S.C. 761 *et seq.*) and the DOE Organization Act (42 U.S.C. 7101 *et seq.*) require the EIA to carry out a centralized, comprehensive, and unified energy information program. This program collects, evaluates, assembles, analyzes, and disseminates information on energy resource reserves, production, demand, technology, and related economic and statistical information. This information is used to assess the adequacy of energy resources to meet near and longer term domestic demands.

The EIA, as part of its effort to comply with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501, *et seq.*), provides the general public and other Federal agencies with opportunities to comment on collections of energy information conducted by or in conjunction with the EIA. Also, the EIA will later seek approval for this collection by the Office of Management and Budget (OMB) under Section 3507(a) of the Paperwork Reduction Act of 1995.

The collected information will be kept in public electronic files available on EIA's Web site (*http://www.eia.gov*). Monthly and annual tabulations of these data may be used by the U.S. Energy Information Administration in the publications: *Annual Energy Outlook, Annual Energy Review, Electric Power Annual, Electric Power Monthly, and Monthly Energy Review.*

The existing survey of electricity imports and exports (OE–781R) was designed to reflect significant changes in the electricity industry, such as the restructuring of wholesale electricity markets and transmission by the Federal Energy Regulatory Commission (FERC); the entry of a large number of independent marketers into those markets; and the regulatory requirement that entities in the electric power industry keep information on transmission service separate from their information on marketing. All of this reduced the usefulness of an earlier version of the survey form.

However, experience with the current collection instrument since it began in July 2010 has shown that the form is overly complex and confusing. It is not providing the type and quality of information expected or required. We also find that some of the information currently collected is not justifiable considering EIA's current budget.

The following is additional information about the energy information collection to be submitted to OMB for review: (1) The collection numbers and title; (2) the sponsor (*i.e.,* the Department of Energy component); (3) the current OMB docket number (if applicable); (4) the type of request (*i.e.,* new, revision, extension, or reinstatement); (5) response obligation (*i.e.,* mandatory, voluntary, or required to obtain or retain benefits); (6) a description of the need for and proposed use of the information; (7) a categorical description of the likely respondents; (8) estimate number of respondents; and (9) an estimate of the total annual reporting burden in hours (*i.e.,* the estimated number of likely respondents times the proposed frequency of response per year times the average hours per response); (10) an estimate of the total annual reporting and recordkeeping cost burden (in thousands of dollars).

1. Form EIA–111, Quarterly Electricity Imports and Exports Report.
2. U.S. Energy Information Administration.
3. OMB Number 1905–NEW.
4. Three-year approval.
5. Mandatory.
6. Form EIA–111 collects U.S. electricity import and export data. The data are used to get an accurate measure of the flow of electricity into and out of the United States. The import and export data are reported by U.S. purchasers, sellers and transmitters of wholesale electricity, including persons authorized by Order to export electric energy from the United States to foreign countries, persons authorized by Presidential Permit to construct, operate, maintain, or connect electric power transmission lines that cross the U.S. international border, and U.S. Balancing Authorities that are directly interconnected with foreign Balancing Authorities. Such entities are to report monthly flows of electric energy received or delivered across the border, the cost associated with the transactions, and actual and implemented interchange. The data collected on this form may appear in various EIA publications.
7. Business or other for-profit; State, local or Tribal government; Federal government.
8. 173 responses per quarter, for a total of 692 responses annually.
9. Annual total of 4,152 hours.
10. Annual total of $0.

II. Current Actions

The EIA is soliciting comments on the proposed Form EIA–111, ''Quarterly Electricity Imports and Exports Report.'' This survey will replace the existing Form OE–781R. Pending authorization to administer the revised form, EIA has suspended the current collection of the OE–781R. Upon receiving authorization to administer the revised form, EIA will terminate the OE–781R and begin operation of the new survey. EIA intends to retroactively collect the core import and export data for the period of the suspension.

The following changes are proposed:

The form would continue to collect data on monthly activity, but respondents would file the form quarterly. Quarterly data would be filed within 30 days of the end of the reporting quarter, *e.g.,* first quarter data would be due no later than April 30. (The existing form collects monthly information each month.)

The current Form OE–781R is mandatory for persons issued orders authorizing them to export electricity from the United States to foreign countries and by owners and operators of international electricity transmission lines authorized by Presidential permit or treaty. The form further asks respondents to categorize themselves as one or more the following: Purchasing and Selling Entity, Transmission System Operator, Transmission Owner, or Treaty Entity.

Currently, only Purchasing and Selling Entities that have been issued orders authorizing them to export electricity from the United States to foreign countries are required to complete the form. This means that information on imports made by Purchasing and Selling Entities without Export Authorizations is not being reported. To ensure reporting of all electricity imports into the U.S., in the new Form EIA–111 we propose to expand mandatory reporting to all Purchasing and Selling Entities that import electricity in to the U.S.

In the new Form EIA–111 we propose to replace the Transmission System Operator category with U.S. Balancing Authorities that are directly interconnected with foreign electricity systems. There are seven such Balancing Authorities: ERCOT, CAISO, Bonneville Power Administration, WAPA Upper

Great Plains East, MISO, NYISO, and ISO–NE.

This change is proposed because under the *NERC Functional Model* (from which three of the current form's respondent categories are derived), Transmission System Operators do not perform the functions necessary for them to provide the required information. In contrast, U.S. border Balancing Authorities are the appropriate entities to report cross-border actual and implemented interchange. Interchange is any energy transfer that crosses Balancing Authority boundaries. Actual Interchange means the metered value electricity that flows from one balancing authority area to another. Implemented Interchange is the interchange values that the Balancing Authority enters into its Area Control Error equation, *i.e.,* uses to balance supply and demand of its electric system.

A number of entities could report implemented interchange provided on the interchange scheduling *e-tags*. Border Balancing Authorities are a convenient provider of this information since they would already be providing actual interchange on the same schedule. Under FERC-approved mandatory reliability standards, Balancing Authorities receive e-tag information from the interchange coordinator when the transmission path is through their system.

We propose to drop the transmission owner respondent category as it is no longer necessary.

The existing survey breakdown of the quantity and value of imports and exports into cost-of-service and market rates would be dropped. The breakdown of volume by fuel source would be dropped. Questions covering the total cost of ancillary service along with a general identification of the type of ancillary services would be dropped.

For each import transaction, the foreign source balancing authority name, the U.S. sink balancing authority name, the presidential permit number or transmission service provider name would be required. On the new Form EIA–111 the type of service is categorized as firm, non-firm, exchange, or other. Payments are broken down into energy revenues, other revenues and total revenues.

For each export transaction, the DOE export authorization number, U.S. source balancing authority name, the foreign sink balancing authority name, the presidential permit number or transmission service provider name would be required. On the new Form EIA–111 the type of service is categorized as firm, non-firm, exchange, or other. Payments are broken down into energy payments, other payments, and total payments.

U.S. border balancing authorities would report actual interchange received from and delivered to directly interconnected foreign border balancing authorities. Instead of scheduled imports and exports reported by transmission operators, U.S. border balancing authorities would report implemented interchange (the current industry term) when the transmission path is through their system, for each combination of source and sink balancing authorities.

Reporting of the characteristics of transmission operations would be replaced by quarterly reporting of events that exceed DOE order terms. Presidential permit and DOE export authorization holders would report their order number, the date and hour(s) of the exceeded event and the specific order term exceeded.

Reporting of existing and proposed transmission facilities crossing the border would be dropped.

III. Request for Comments

Prospective respondents and other interested parties should comment on the actions discussed in item II. The following guidelines are provided to assist in the preparation of comments.

As a Potential Respondent to the Request for Information

A. Is the proposed collection of information necessary for the proper performance of the functions of the agency and does the information have practical utility?

B. What actions could be taken to help ensure and maximize the quality, objectivity, utility, and integrity of the information to be collected?

C. Are the instructions and definitions clear and sufficient? If not, which instructions need clarification?

D. Can the information be submitted by the respondent by the due date?

E. Public reporting burden for this collection is estimated to average 6 hours per quarter for each respondent. The estimated burden includes the total time necessary to provide the requested information. In your opinion, how accurate is this estimate?

F. The agency estimates that the only cost to a respondent is for the time it will take to complete the collection. Will a respondent incur any start-up costs for reporting, or any recurring annual costs for operation, maintenance, and purchase of services associated with the information collection?

G. What additional actions could be taken to minimize the burden of this collection of information? Such actions may involve the use of automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

H. Does any other Federal, State, or local agency collect similar information? If so, specify the agency, the data element(s), and the methods of collection.

As a Potential User of the Information To Be Collected

A. Is the proposed collection of information necessary for the proper performance of the functions of the agency and does the information have practical utility?

B. What actions could be taken to help ensure and maximize the quality, objectivity, utility, and integrity of the information disseminated?

C. Is the information useful at the levels of detail to be collected?

D. For what purpose(s) would the information be used? Be specific.

E. Are there alternate sources for the information and are they useful? If so, what are their weaknesses and/or strengths?

Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval of the form. They also will become a matter of public record.

Statutory Authority: Section 13(b) of the Federal Energy Administration Act of 1974, Pub. L. 93–275, codified at 15 U.S.C. 772(b).

Issued in Washington, DC on August 3, 2011.

Stephanie Brown,

Director, Office of Survey Development and Statistical Integration, U. S. Energy Information Administration.

[FR Doc. 2011–20401 Filed 8–10–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP11–526–000]

Enbridge Offshore Pipelines (UTOS) LLC; Notice of Application

Take notice that on August 1, 2011, Enbridge Offshore Pipelines (UTOS) LLC, (UTOS) filed an application in Docket No. CP11–526–000 pursuant to section 7(b) of the Natural Gas Act and Part 157 of the Commission's Regulations, seeking authorization to abandon all services it provides under its Part 284 blanket certificate and to abandon its physical certificated facilities which are located onshore and in federal and state waters offshore

Louisiana, and to defer the ultimate disposition of these facilities for up to three years. In the alternative, UTOS seeks authorization to deactivate its facilities for up to three years and seek abandonment at that time, all as more fully set forth in the application which is on file with the Commission and open for public inspection. UTOS asserts that its proposal is consistent with the recently Commission approved settlement in Docket No. RP10–1393.

Any questions regarding this application should be directed to Cynthia Hornstein Roney, Manager, Regulatory Compliance, Enbridge Offshore Pipelines (UTOS) LLC, 1100 Louisiana, Suite 3300, Houston, Texas 77002, or call at (832) 214–9334.

Pursuant to section 157.9 of the Commission's rules, 18 CFR 157.9, within 90 days of this Notice the Commission staff will either: complete its environmental assessment (EA) and place it into the Commission's public record (eLibrary) for this proceeding; or issue a Notice of Schedule for Environmental Review. If a Notice of Schedule for Environmental Review is issued, it will indicate, among other milestones, the anticipated date for the Commission staff's issuance of the final environmental impact statement (FEIS) or EA for this proposal. The filing of the EA in the Commission's public record for this proceeding or the issuance of a Notice of Schedule for Environmental Review will serve to notify Federal and state agencies of the timing for the completion of all necessary reviews, and the subsequent need to complete all Federal authorizations within 90 days of the date of issuance of the Commission staff's FEIS or EA.

There are two ways to become involved in the Commission's review of this project. First, any person wishing to obtain legal status by becoming a party to the proceedings for this project should, on or before the comment date stated below, file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, a motion to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the NGA (18 CFR 157.10). A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies of all documents filed by the applicant and by all other parties. A party must submit 7 copies of filings made with the Commission and must mail a copy to the applicant and to every other party in the proceeding. Only parties to the proceeding can ask for court review of Commission orders in the proceeding.

However, a person does not have to intervene in order to have comments considered. The second way to participate is by filing with the Secretary of the Commission, as soon as possible, an original and two copies of comments in support of or in opposition to this project. The Commission will consider these comments in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. The Commission's rules require that persons filing comments in opposition to the project provide copies of their protests only to the party or parties directly involved in the protest.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Environmental commentors will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. Environmental commentors will not be required to serve copies of filed documents on all other parties. However, the non-party commentors will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

The Commission strongly encourages electronic filings of comments, protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 7 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: August 26, 2011.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20430 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP11–524–000]

Texas Eastern Transmission, LP; Notice of Application

Take notice that on July 29, 2011, Texas Eastern Transmission, LP (Texas Eastern), 5400 Westheimer Court, Houston, Texas 77056–5310, filed with the Federal Energy Regulatory Commission (Commission) an application under section 7(b) of the Natural Gas Act (NGA) for authorization to abandon in place four reciprocating compressor units with a total of 4,400 horsepower and related appurtenances at Station No. 21–A of its Uniontown Compressor Station located in Fayette County, Pennsylvania. Texas Eastern states that there will be no termination or reduction in service to any existing customers of Texas Eastern as a result of the proposed abandonment of these facilities, all as more fully set forth in the application which is on file with the Commission and open to public inspection. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site Web at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TTY, (202) 502–8659.

Any questions regarding the application should be directed to Lisa A. Connolly, General Manager, Rates & Certificates, Texas Eastern Transmission, LP, P.O. Box 1642, Houston, Texas 77251–1642, or telephone (713) 627–4102, or fax (713) 627–5947 or by e-mail *laconnolly@spectraenergy.com.*

Pursuant to section 157.9 of the Commission's rules, 18 CFR 157.9, within 90 days of this Notice the Commission staff will either: Complete its environmental assessment (EA) and place it into the Commission's public record (eLibrary) for this proceeding; or issue a Notice of Schedule for Environmental Review. If a Notice of Schedule for Environmental Review is issued, it will indicate, among other milestones, the anticipated date for the Commission staff's issuance of the final environmental impact statement (FEIS) or EA for this proposal. The filing of the EA in the Commission's public record for this proceeding or the issuance of a Notice of Schedule for Environmental Review will serve to notify Federal and state agencies of the timing for the completion of all necessary reviews, and the subsequent need to complete all Federal authorizations within 90 days of the date of issuance of the Commission staff's FEIS or EA.

There are two ways to become involved in the Commission's review of this project. First, any person wishing to obtain legal status by becoming a party to the proceedings for this project should, on or before the comment date stated below file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, a motion to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the NGA (18 CFR 157.10). A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies of all documents filed by the applicant and by all other parties. A party must submit seven copies of filings made in the proceeding with the Commission and must mail a copy to the applicant and to every other party. Only parties to the proceeding can ask for court review of Commission orders in the proceeding.

However, a person does not have to intervene in order to have comments considered. The second way to participate is by filing with the Secretary of the Commission, as soon as possible, an original and two copies of comments in support of or in opposition to this project. The Commission will consider these comments in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. The Commission's rules require that persons filing comments in opposition to the project provide copies of their protests only to the party or parties directly involved in the protest.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Environmental commentors will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. Environmental commentors will not be required to serve copies of filed documents on all other parties. However, the non-party commentors will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

The Commission strongly encourages electronic filings of comments, protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and seven copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

Comment Date: August 26, 2011.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20429 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER11–3829–001.
Applicants: Wisconsin Power and Light Company.
Description: Wisconsin Power and Light Company submits tariff filing per 35.17(b): WPL NSP—LBAAOCA Amendment to be effective 6/20/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5018.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–3957–001.
Applicants: Consumers Energy Company.
Description: Consumers Energy Company submits tariff filing per 35.17(b): Facilities Agreement with the Michigan Power Limited Partnership, Rate Schedule to be effective 8/29/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5054.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4219–000.
Applicants: Wolverine Power Supply Cooperative, Inc., Michigan Electric Transmission Company, LLC.
Description: Wolverine Power Supply Cooperative, Inc. submits tariff filing per 35.13(a)(2)(iii: Filing of Amended and Restated Interconnection Agreements to be effective 4/21/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5017.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4220–000.
Applicants: California Independent System Operator Corporation.
Description: California Independent System Operator Corporation submits tariff filing per 35.13(a)(2)(iii: 2011–08–02 CAISO Amendment to Clarify section 37.2.1.1 to be effective 10/3/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5052.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4221–000.
Applicants: California Independent System Operator Corporation.
Description: California Independent System Operator Corporation submits tariff filing per 35: 2011–08–04 CAISO Filing in Compliance with July 5 Order re Order 719 to be effective 8/4/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5053.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4222–000.
Applicants: PJM Interconnection, LLC.
Description: PJM Interconnection, LLC submits tariff filing per 35.13(a)(2)(iii: Queue No. W2–064; Original Service Agreement No. 2976 to be effective 7/11/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5058.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4223–000.
Applicants: PJM Interconnection, LLC.
Description: PJM Interconnection, LLC submits tariff filing per 35.13(a)(2)(iii: Queue No. W2–074; Original Service Agreement No. 2977 to be effective 7/11/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5070.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4224–000.
Applicants: Midwest Independent Transmission System, Inc., ITC Midwest LLC.
Description: Midwest Independent Transmission System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: Filing of Notice of Succession to Interconnection Agreement to be effective 10/4/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5071.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4225–000.
Applicants: PJM Interconnection, LLC.
Description: PJM Interconnection, LLC submits tariff filing per 35.13(a)(2)(iii: Queue No. W1–082; Original Service Agreement No. 2975 to be effective 7/11/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5072.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4226–000.
Applicants: Southern California Edison Company.
Description: Southern California Edison Company submits tariff filing per 35.13(a)(2)(iii: Letter Agreement for SunPower & Sempra Gen, Whirlwind Projects to be effective 8/3/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5073.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4228–000.
Applicants: PJM Interconnection, LLC.
Description: PJM Interconnection, LLC submits tariff filing per 35.13(a)(2)(iii: Revisions to section 7.3.6 of the OATT Attachment K Appendix and OA Schedule 1 to be effective 8/5/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5080.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4229–000.
Applicants: Midwest Independent Transmission System, Inc., ITC Midwest LLC.
Description: Midwest Independent Transmission System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: Filing of Notice of Succession of ITC Midwest to be effective 10/4/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5081.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4230–000.
Applicants: Midwest Independent Transmission System, Inc., ITC Midwest LLC.
Description: Midwest Independent Transmission System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: Notice of Succession to be effective 10/4/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5083.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4231–000.
Applicants: Midwest Independent Transmission System, Inc., ITC Midwest LLC.
Description: Midwest Independent Transmission System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: Filing of Notice of Succession to be effective 10/4/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5084.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4232–000.
Applicants: Midwest Independent Transmission System, Inc., ITC Midwest LLC.
Description: Midwest Independent Transmission System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: Filing of Notice of Succession to be effective 10/4/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5098.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4233–000.
Applicants: Appalachian Power Company.
Description: Appalachian Power Company submits tariff filing per 35.13(a)(2)(iii: 20110804 Attachment K and L Revision to be effective 9/6/2011.
Filed Date: 08/04/2011.
Accession Number: 20110804–5100.
Comment Date: 5 p.m. Eastern Time on Thursday, August 25, 2011.

Docket Numbers: ER11–4234–000.
Applicants: Avista Corporation.
Description: Avista Corporation submits tariff filing per 35.12: Avista Corp Rate Schedule FERC No. 527 to be effective 10/1/2011.
Filed Date: 08/05/2011.
Accession Number: 20110805–5001.
Comment Date: 5 p.m. Eastern Time on Friday, August 26, 2011.

Docket Numbers: ER11–4235–000.
Applicants: PacifiCorp.
Description: Notices of Cancellation of Pacificorp.
Filed Date: 08/05/2011.
Accession Number: 20110805–5019.
Comment Date: 5 p.m. Eastern Time on Friday, August 26, 2011.

Docket Numbers: ER11–4236–000.
Applicants: Duke Energy Commercial Asset Management, Inc.
Description: Notices of Cancellation of Duke Energy Commercial Asset Management, Inc.
Filed Date: 08/05/2011.
Accession Number: 20110805–5020.
Comment Date: 5 p.m. Eastern Time on Friday, August 26, 2011.

Take notice that the Commission received the following electric securities filings:

Docket Numbers: ES11–38–000.
Applicants: Upper Peninsula Power Company.
Description: Upper Peninsula Power Company submits supplement to their 6/15/11 application for renewed authorization to issue long-term debate.
Filed Date: 08/02/2011.
Accession Number: 20110805–0017.
Comment Date: 5 p.m. Eastern Time on Friday, August 12, 2011.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20426 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL11–56–000]

FirstEnergy Service Co. v. Midwest Independent Transmission System Operator, Inc.; Notice of Petition for Declaratory Order and Complaint

Take notice that on August 3, 2011, FirstEnergy Service Company filed a petition for declaratory order asking that the Commission declare that Multi-Value Project (MVP) transmission usage charges proposed by the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) in Docket No. ER10–1791 may not, by their own terms, be imposed on departing transmission owners or loads. In the alternative, First Energy Service Co. filed a formal complaint, pursuant to section 206 of the Federal Power Act and Rule 206 of the Commission's Rules of Practice and Procedure, alleging that it is unjust and unreasonable to apply MVP transmission usage charges to FirstEnergy or its customers migrated from the Midwest ISO to PJM Interconnection, LLC effective June 1, 2011.

FirstEnergy certifies that copies of the complaint were served on the contacts for the Midwest ISO as listed on the Commission's list of Corporate Officials and on parties to the proceeding in Docket No. ER10–1791.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern Time on September 2, 2011.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20433 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EF11–8–000]

Bonneville Power Administration; Notice of Filing

Take notice that on August 1, 2011, the Bonneville Power Administration submitted its Proposed 2012 Wholesale Power and Transmission Rates Rate Adjustment, for confirmation and approval, to be effective October 1, 2011.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern Time on August 31, 2011.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20431 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP11–520–000]

Northwest Pipeline GP; Notice of Request Under Blanket Authorization

Take notice that on July 26, 2011, Northwest Pipeline GP (Northwest), 295 Chipeta Way, Salt Lake City, Utah 84108, filed a prior notice request pursuant to sections 157.205, 157.208, and 157.210 of the Commission's regulations under the Natural Gas Act (NGA) and Northwest's blanket certificate issued in Docket No. CP82–433–000 for authorization to replace, construct and operate certain mainline pipeline facilities (North Seattle Delivery Lateral Expansion Project) located in Snohomish County, Washington to provide 84,200 dekatherms per day of new delivery capacity for Puget Sound Energy Inc. (Puget). Specifically, Northwest proposes to replace 2.2 miles of 8-inch diameter pipeline on the North Seattle Delivery Lateral with new 20-inch diameter pipeline, modify a meter station, and install miscellaneous appurtenances at a cost of approximately $12.8 million for which Northwest will be reimbursed by Puget through a facilities charge, all as more fully set forth in the application, which is on file with the Commission and open to public inspection.

The filing may also be viewed on the Web at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (866) 208–3676 or TTY, (202) 502–8659.

Any questions regarding this prior notice should be directed to Pam Barnes, Manager, Certificates and Tariffs, at (801) 584–6857, Northwest Pipeline GP, P.O. Box 58900, Salt Lake City, Utah 84158–0900, or by e-mail *pam.j.barnes@williams.com.*

Any person may, within 60 days after the issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention. Any person filing to intervene or the Commission's staff may, pursuant to section 157.205 of the Commission's regulations under the NGA (18 CFR 157.205) file a protest to the request. If no protest is filed within the time allowed, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to section 7 of the NGA.

The Commission strongly encourages electronic filings of comments, protests, and interventions via the Internet in lieu of paper. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://*

www.ferc.gov) under the ''e-Filing'' link. Persons unable to file electronically should submit an original and 7 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20428 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of FERC Staff Attendance at the Entergy ICT Transmission Planning Summit and Entegry Regional State Committee Meeting

The Federal Energy Regulatory Commission hereby gives notice that members of its staff may attend the meetings noted below. Their attendance is part of the Commission's ongoing outreach efforts.

Entergy ICT Transmission Planning Summit

August 23, 2011 (8 a.m.–5 p.m.)

Entergy Regional State Committee Meeting

August 24, 2011 (1–5 p.m.)
August 25, 2011 (9 a.m.–12 p.m.)

These meetings will be held at the Sheraton New Orleans, 500 Canal Street, New Orleans, LA 70130. The hotel phone number is 888–627–7033.

The discussions may address matters at issue in the following proceedings:

Docket No.	
OA07–32	Entergy Services, Inc.
EL00–66	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL01–88	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL07–52	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL08–51	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL08–60	*Ameren Services Co.* v. *Entergy Services, Inc.*
EL09–43	*Arkansas Public Service Commission* v. *Entergy Services, Inc.*
EL09–50	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL09–61	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL10–55	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL10–65	*Louisiana Public Service Commission* v. *Entergy Services, Inc.*
EL11–34	Midwest Independent System Transmission Operator, Inc.
ER05–1065	Entergy Services, Inc.
ER07–682	Entergy Services, Inc.
ER07–956	Entergy Services, Inc.
ER08–1056	Entergy Services, Inc.
ER09–833	Entergy Services, Inc.
ER09–1224	Entergy Services, Inc.
ER10–794	Entergy Services, Inc.
ER10–1350	Entergy Services, Inc.
ER10–1676	Entergy Services, Inc.
ER10–2001	Entergy Arkansas, Inc.
ER10–2161	Entergy Texas, Inc.
ER10–2748	Entergy Services, Inc.
ER10–3357	Entergy Arkansas, Inc.
ER11–2131	Entergy Arkansas, Inc.
ER11–2132	Entergy Gulf States, Louisiana, LLC
ER11–2133	Entergy Gulf States, Louisiana, LLC
ER11–2134	Entergy Mississippi, Inc.
ER11–2135	Entergy New Orleans, Inc.
ER11–2136	Entergy Texas, Inc.
ER11–2161	Entergy Texas, Inc.
ER11–3156	Entergy Arkansas, Inc.
ER11–3157	Entergy Arkansas, Inc.
ER11–3274	Entergy Arkansas, Inc.
ER11–3728	Midwest Independent Transmission System Operator, Inc.
ER11–3657	Entergy Arkansas, Inc.
ER11–3658	Entergy Arkansas, Inc.

These meetings are open to the public.

For more information, contact Patrick Clarey, Office of Energy Market Regulation, Federal Energy Regulatory Commission at (317) 249–5937 or *patrick.clarey@ferc.gov.*

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20425 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 7742–007]

Steve Mason Enterprises, Inc., Green Energy Trans, LLC; Notice of Transfer of Exemption

1. Pursuant to section 4.106(i) of the Commission's regulations,[1] Steve Mason Enterprises, Inc., exemptee for the Long Shoals Project No. 7742,[2] informed the Commission that it transferred ownership of its exempted project property and facilities for Project No. 7742 to Green Energy Trans, LLC.[3] The project is located on the South Fork Catawba River in Lincoln County, North Carolina. The transfer of an exemption does not require Commission approval.[4]

2. Green Energy Trans, LLC, located at 227 Pilch Road, Troutman, North Carolina, is now the exemptee of the Long Shoals Project No. 7742.

Dated: August 5, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–20432 Filed 8–10–11; 8:45 am]

BILLING CODE 6717–01–P

[1] 18 CFR 4.106(i) (2011).

[2] The Commission issued an exemption from licensing for Project No. 7742 on July 19, 1984. *Long Shoals Hydro, Inc.,* 28 FERC ¶ 62,067 (1984).

[3] *See* filing of May 26, 2011 from Steve Mason Enterprises, Inc.

[4] *E.g., John C. Jones,* 99 FERC ¶ 61,372, at 62,580 n.2 (2002).

DEPARTMENT OF ENERGY

Western Area Power Administration

Information Collection Request Extension Submitted to the Office of Management and Budget (OMB) for Approval Under the Paperwork Reduction Act

AGENCY: Western Area Power Administration, U.S. Department of Energy.

ACTION: Notice of Extension under the Paperwork Reduction Act Submitted to OMB for Approval; Request for Comments.

SUMMARY: This notice announces that Western Area Power Administration (Western), an agency within the Department of Energy (DOE), has submitted an extension to an existing Information Collection Request (ICR) to the Office of Management and Budget (OMB) for review, comment and approval as required under the Paperwork Reduction Act of 1995.[1] The ICR Western seeks to extend its Applicant Profile Data form (APD). The ICR described below identifies the proposal, including the anticipated public burdens. On April 6, 2011, Western published a notice in the **Federal Register** inviting public comments on the extension of its existing ICR.[2] That notice provided a 60-day comment period. Western included a summary of the comments and responses below. Western now

[1] *See* 44 U.S.C. 3501, *et seq.*

[2] *See* 76 FR 19067 (2011).

invites interested entities to submit comments to OMB.

Western is collecting and will continue to collect the data under its APD to properly perform its function of marketing a limited amount of Federal hydropower. Western will use the collected data to evaluate who will receive an allocation of Federal power.

Western notes the Paperwork Reduction Act and associated **Federal Register** notice is a process whereby Western obtains approval from OMB to collect information from the public. It is a legal requirement Western must comply with before requesting potential preference customers to submit an application for power. The Paperwork Reduction Act is not the process where interested parties request an allocation of Federal power. The allocation of power from Western is outside the scope of this process and is completed in a separate process by each Western region, when required.

DATES: To ensure consideration, comments regarding this collection must be received on or before September 12, 2011. The Paperwork Reduction Act requires OMB to make a decision on the extension of the ICR within 60 days after this publication or receipt of the proposed collection of information, whichever is later.

ADDRESSES: Written comments should be sent to: The DOE Desk Officer, Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Room 10102, 735 17th Street, NW., Washington, DC 20503.

With a copy to Western at: *PRAcomments@wapa.gov* or Western Area Power Administration, Ronald Klinefelter, 12155 W. Alameda Parkway, Lakewood, CO 80228.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the APD and instructions should be directed to Western Area Power Administration, Ronald Klinefelter, (720) 962–7010.

SUPPLEMENTARY INFORMATION:

I. Statutory Authority

Reclamation Laws rose from the Desert Land Act of 1872 and include, but are not limited to: the Desert Land Act of 1872, Reclamation Act of 1902, Reclamation Project Act of 1939, and the Acts authorizing each individual project such as the Central Valley Project Authorizing Act of 1937.[3] The Reclamation Act of 1902 established the Federal reclamation program.[4] The basic principle of the Reclamation Act of 1902 was the United States, through the Secretary of the Interior, would build and operate irrigation works from the proceeds of public land sales in the 16 arid Western states (a 17th was added later). The Reclamation Project Act of 1939 expanded the purposes of the reclamation program and specified certain terms for the Interior's water and power contracts.[5] Congress enacted the Reclamation Laws to enhance navigation and flood protection, reclaim arid lands in the western United States, and protect fish and wildlife.[6] Congress, generally, intended the production of power to be a supplemental feature of the multi-purpose water projects authorized under the Reclamation Laws.[7] No contract entered into by the United States for power may impair the irrigation purposes.[8] Section 5 of the Flood Control Act of 1944 is read *in pari materia* with Reclamation Laws.[9] In 1977, the Department of Energy Organization Act transferred the power marketing functions from the Department of the Interior to Western.[10] Pursuant to this authority, Western markets Federal hydropower. As part of Western's marketing authority, Western needs to obtain information from interested entities who desire an allocation of Federal power. The Paperwork Reduction Act requires Western to obtain a clearance from OMB before collecting certain information.[11]

II. Background

Western is a Federal agency under DOE that markets and transmits wholesale electric power from 56 Federal hydropower plants and one coal-fired plant. Western sells about 40 percent of regional hydroelectric generation in a service area that covers 1.3 million square miles in 15 states.[12] To deliver this electric power to the western half of the United States, Western markets and transmits about 10,000 megawatts of hydropower across an integrated 17,000-circuit mile, high voltage transmission system. Western's statutorily defined preference customers include municipalities, cooperatives, public utility and irrigation districts, Federal and State agencies, and Native American Tribes.[13] These customers, in turn, provide retail electric service to millions of consumers in Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah, and Wyoming.

As part of its marketing mission, Western needs to continue to collect information contained in the APD from entities that may be interested in obtaining a power allocation from Western. Western is submitting this extension with the accompanying ICR to OMB with this notice.[14] Western has analyzed and responded to all comments received through this process. As required by the Paperwork Reduction Act, Western is now publishing a notice of its submittal to OMB and providing a second opportunity to comment.[15] Such comments should be sent directly to OMB with a copy to Western at the addresses listed above.

III. Process

A. Background

On April 6, 2011, in compliance with the Paperwork Reduction Act, Western published a notice in the **Federal Register** inviting comments on extending Western's APD.[16] As part of that notice, in particular, Western invited comments on: (1) Whether the proposed continued collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of burden, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology. Western provided notice that the proposed APD will not be part of a system of records covered by the

[3] *See* Ch. 107, 19 Stat. 377 (1872), Ch. 1093, 32 Stat. 388 (1902), Ch, 418, 53 Stat. 1187 (1939), Ch. 832, 50 Stat. 844, 850 (1937), all as amended and supplemented.

[4] *See* Ch. 1093, 32 Stat. 388 (1902), as amended and supplemented.

[5] *See* Ch. 418, 53 Stat. 1187 (1939), as amended and supplemented.

[6] *See, e.g.,* Ch. 832, 50 Stat. 844, 850 (1937), as amended and supplemented.

[7] *See, e.g.,* Ch. 832, 50 Stat. 844, 850 (1937), as amended and supplemented.

[8] 43 U.S.C. 485h(c).

[9] *See* Ch. 665, 58 Stat. 887 (1944), as amended and supplemented.

[10] *See* 42 U.S.C. 7152(a)(1)(E).

[11] *See* 44 U.S.C. 3501, *et seq.*

[12] Western markets power under marketing plans developed through its offices: the Rocky Mountain Region, Upper Great Plains Region, Rocky Mountain Region, Sierra Nevada Region and the Colorado River Storage Project Management Center (Regions).

[13] *See, e.g.,* 43 U.S.C. 485h(c).

[14] *See* 44 U.S.C. 3507.

[15] *See* 44 U.S.C. 3506.

[16] *See* 76 FR 19067 (2011).

Privacy Act [17] and will be available under the Freedom of Information Act.[18]

In April 2011, Western published a copy of the **Federal Register** notice and an invitation for comments on its Web site.[19] Western sent a notice to over 850 potentially interested entities and customer groups, informing them of the publication of the **Federal Register** notice and invitational comments. This notice took the form of an e-mail from Western's Regional Offices located in California, Arizona, Montana, Colorado and Utah. The notices were sent to stakeholders in Western's service territory, which includes, but is not limited to, California, Nevada, Arizona, Utah, New Mexico, Colorado, Wyoming, Montana, Texas, North Dakota and South Dakota. Western received one comment letter. Western's responses to the comments are below.

B. Response to Comments

Comment: The comment supports the continued use of the APD and sees no reason its use should not be extended beyond September 30, 2011.

Response: Western agrees the APD should be extended.

Comment: The comment raised a concern about the **Federal Register** notice. In particular, while the commenter understands that in drafting **Federal Register** notices brevity sometimes begets generalities, the commenter requested that in future **Federal Register** notices Western be more descriptive and provide a more accurate representation of Reclamation Law rather than general statements.

Response: Western appreciates the commenter's point that individual projects have unique attributes defined by specific legislation. Reclamation Laws are not a single act, but rather are comprised of numerous acts for multiple projects. The Department of the Interior has a publication that spans five volumes and two supplements annotating Reclamation Laws.[20] Within the confines of a **Federal Register** notice for the Paperwork Reduction Act, it would be impractical to delve into the nuances of provisions contained in multiple acts for multiple projects located within Western's service region. As stated in the 60-day **Federal Register** notice, Reclamation Laws are a series of laws arising from the Desert Land Act of 1872 and include but are not limited to: the Desert Land Act of 1872, Reclamation Act of 1902, Reclamation Project Act of 1939, and the acts authorizing each individual project, such as the Central Valley Project (CVP) Reauthorizing Act of 1937.[21] Each project also may be comprised of additional components. Given the APD spans all of Western's regions and its multiple projects, Western's **Federal Register** notice was necessarily of wide applicability. Furthermore, for a Paperwork Reduction Act process, given the sheer volume of Reclamation Laws, it is impractical to identify the statutory authority for each and every project and each and every project component. Western has included and will continue to include phrases such as "including," "but not limited to," and "for instance" in future **Federal Register** notices that have general applicability to the multiple projects throughout Western's regions.

Comment: The comment also mentioned concerns regarding the potential impact general statutory references in this proceeding could have on pending legislation related to the remarketing of the Boulder Canyon Project in the United States Congress.

Response: As mentioned in the response above, Western believes use of general statutory references is necessary in this **Federal Register** notice given the broad applicability of the APD. The Boulder Canyon Project remarketing effort is outside the scope of this process and any concerns about the impact of general statutory references of this **Federal Register's** process should be addressed in that proceeding.

IV. Purpose of Proposed Collection

The APD is necessary for the proper performance of Western's functions. Western markets a limited amount of Federal power. Western has discretion to determine who will receive an allocation. Due to the high demand for Western's power and limited amount of available power, Western needs to be able to collect information to evaluate who will receive an allocation. As a result, the information Western collects is both necessary and useful.

This public process only determines what type of information Western will collect in the APD from an entity applying for a Federal power allocation. The information Western proposes to collect is voluntary. Western will use the information collected in the APD (and has used the information collected under the current OMB-approved control number), in conjunction with its marketing plan, to determine an entity's eligibility and, ultimately, who will receive an allocation of Federal power. Western will issue a Call for Applications as part of its marketing plan, which will occur through a separate process. The actual allocation of power is outside the scope of this proceeding.

V. Information Western Proposes To Continue To Collect

A. Applicant Profile Data (APD)

Western has submitted to OMB the request to extend Western's APD. As part of this process, Western has identified what it believes is the minimum amount of information Western needs for its regional offices to properly perform the functions of the agency. Due to the variations that may develop in each region, the region, through its marketing plan, may determine that it does not need all of the information contained in the APD. As a result, Western proposes to allow each region to use subsets of the form, where one region's APD may request less information than another region's APD. Rather than over collect unnecessary information, Western seeks to collect only the minimal amount of information it needs. Western evaluated the possibility of using the same APD form but instructing applicants to fill out only certain sections. This approach could lead to an applicant ignoring or misunderstanding Western's instructions and providing unnecessary information. Using a subset of information will lead to a more consistent process and will minimize the time an applicant uses to complete the APD.

To receive an allocation of Federal power from Western, the applicant must provide the information requested in the APD. If the requested information is not applicable or is not available, the applicant will note it on the APD. Western will request, in writing, additional information from any applicant whose application is deficient. Western will notify the applicant when the application is due. In the event an applicant fails to provide sufficient information to allow Western to make a determination regarding eligibility by the due date, the application will not be considered.

B. Form of APD

A copy of the APD is available on Western's Web site at *http://www.wapa.gov.*

[17] *See* 5 U.S.C. 552(a).

[18] *See* 5 U.S.C. 552. Western reserves the right to redact information to protect confidential or sensitive information, as provided under FOIA.

[19] *See* 76 FR 19067 (2011).

[20] *See Federal Reclamation and Related Laws Annotated,* (1972), as supplemented (2001).

[21] *See* Ch. 107, 19 stat. 377 (1872), Ch. 1093, 32 Stat. 388 (1902), Ch, 418, 53 Stat. 1187 (1939), ch. 832, 50 Stat. 844, 850 (1937), all as amended and supplemented.

VI. Paperwork Reduction Requirements

A. Introduction

1. *OMB Number:* Western's existing OMB Number is 1910–5136. This number is displayed on the front page of the APD. It expires on September 30, 2011.

2. *Title:* Applicant Profile Data.

3. *Type of Review:* Western is seeking to extend its APD for 3 years.

4. *Purpose:* The APD is necessary for the proper performance of Western's functions. Western markets a limited amount of Federal power. Western has discretion to determine who will receive an allocation. Due to the high demand for Western's power and limited amount of available power under established marketing plans, Western needs to be able to collect information to evaluate who will receive an allocation. As a result, the information Western collects is both necessary and useful. This public process only determines the information Western will collect in its application. The actual allocation of Federal power will be done through a separate process and is outside the scope of this proceeding.

5. *Respondent:* The response is voluntary. However, if an entity seeks an allocation of Federal power, the applicant must submit an APD. Western has identified the following class of respondents as the most likely to apply: municipalities, cooperatives, public utilities, irrigation districts, Native American Tribes, and Federal and State agencies. The respondents will be located in Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah, and Wyoming.

6. *Estimated Number of Respondents.* Depending on the amount of power that becomes available for allocation, Western anticipates it could receive approximately 100 requests for power during the 3-year period when the OMB Clearance Number is in effect. Western does not anticipate annual responses. The responses will be periodic and occur when Western has power available under an allocation process.

7. *Number of Burden Hours:*

a. *Initial Application:* Western anticipates that it will take less than 8 hours to complete the APD. Once the respondent completes the APD, it will submit the APD to Western for Western's review. After submitting the APD, provided the APD is complete and no clarification is required, Western does not anticipate requiring any further information for the APD from the applicant, unless the applicant is successful in obtaining a power allocation. The applicant submits only one APD. It does not submit an APD every year. If the applicant receives a power allocation, the applicant will need to complete a standard contract to receive its power allocation. Western's standard contract terms are outside the scope of this process.

b. *Recordkeeping:* There is no mandatory recordkeeping requirement on the applicant if it does not receive an allocation of Federal power. In such case, any recordkeeping of the APD by a respondent is voluntary. For those entities that receive a Federal power allocation, Western requires the successful applicant keep the information for 3 years after the applicant signs its Federal power contract. The 3-year, record retention policy will allow Western sufficient time to administer the contract and to ensure the applicant provided factual information in its application. A 3-year record retention policy will have little impact on most businesses in the electric utility industry. Western anticipates that it would take less than 1 hour per successful candidate, per year, for recordkeeping purposes. Western anticipates that in a 3-year period, Western will have approximately 30 successful applicants.

c. *Methodology:* Based on the total number of burden hours and the total number of applications described above, Western expects that over a 3-year period, the total burden hours to complete the APD is 800 hours (100 applicants over 3 years × 8 hours per applicant). This converts to an annual hourly burden of 266.667 hours. An entity will only complete the APD once. It is not required each year.

Based on the above, Western anticipates that there will be additional cost burdens for recordkeeping of 1 hour per year for each who receives a Federal power allocation. Western anticipates that over the course of 3 years there will be 30 successful applicants. The power may be allocated in year 1, year 2 or year 3. For the purposes of determining the cost burden, Western will presume all 30 applicants received an allocation in year 1. As a result, the annual hourly burden for recordkeeping is 30 hours.

For the purposes of this cost burden analysis, Western is assuming that a utility staff specialist will complete the APD. Western estimates a utility staff specialist rate, including administrative overhead, to be approximately $108/hour. For recordkeeping, Western estimates an administrative support rate of $54/hour. Based on the above, Western estimates the total annual cost as (266.667 hour/year × $108/hour) + (30 hour/year × $54/hour) = $30,420.00 per year.

Using the above estimates, on a per applicant basis, assuming the applicant receives a Federal power allocation, the total cost for the applicant over a 3-year period is $1026. The cost to complete the APD is a onetime cost of $864. In addition to the onetime cost, the applicant, if it successfully receives a power allocation, will incur an additional expense of 1 hour for recordkeeping per year × $54 per hour for a total recordkeeping cost of $162 for 3 years.

d. *Summary of Burdens:*

TABLE 1—ANNUAL HOUR BURDEN ESTIMATES

Activity	Number of respondents	Number of responses per respondent	Average burden hour per response	Sub-total burden hours
APD	33.333	1	8	266.67
Recordkeeping	30	1	1	30.00
Total Burden				296.67

TABLE 2—ANNUAL COST BURDEN ESTIMATE

Instrument	Number of respondents	Number of responses per respondent	Average annual burden hour	Cost per burden hour	Cost per response	Sub-total cost
Prepare APD	33.333	1	8	$108	$864.00	$28,800
Recordkeeping	30	1	1	54	54.00	1,620.00
Total Cost						30,420

The procedure and process for the allocation of power shall be the subject matter of a separate notice and is outside the scope of this process.

B. Does the collection of data avoid unnecessary duplication?

To avoid unnecessary duplication, only entities that desire a new Western allocation are required to submit an APD.

As it relates to each of the components of the APD, there is no duplication. Section 1 is information Western needs to determine who the applicant is, whether the applicant is a statutorily-defined preference entity, and whether the applicant is ready, willing, and able to receive and/or distribute Federal power. Section 2 identifies the amount of Federal power that the applicant requests. Section 3 identifies the applicant's loads. Section 4 identifies the applicant's resources. Section 5 identifies the applicant's transmission delivery arrangements necessary to receive Federal power. Section 6 is voluntary and provides the applicant with the ability to provide any additional information. Section 7 is an attestation that the information provided is true and accurate to the best of the applicant's knowledge.

C. Does the collection reduce the burden on the respondent, including small entities, to the extent practicable and appropriate?

The information requested is the minimum amount of information to determine whether the applicant qualifies as a statutorily-defined preference entity and is ready, willing, and able to receive an allocation of Federal power.

D. Does the collection use plain, coherent, and unambiguous language that is understandable to the respondent?

The collection uses plain, coherent, and unambiguous language that is understandable to the target audience. The terms are those used in the electric utility industry. Western does not market power to individual members of the public such as homeowners or shopkeepers. Preference entities are statutorily-designated potential customers who generally are involved in the power business. As a result, the language used in the application is understandable to the target audience.

E. Is the collection consistent with and compatible with the respondent's current reporting and recordkeeping practices to the maximum extent practicable?

The information collection is voluntary. Western will use the information to determine whether an applicant qualifies as a preference entity to receive an allocation of Federal power. As discussed above, there is no mandatory recordkeeping requirement on the applicant if it does not receive an allocation of Federal power. For those entities that receive a Federal power allocation, Western requires that they keep the information for 3 years after Western grants the power allocation and the applicant signs a Federal power contract. The proposed 3-year record retention policy for such applicants would allow Western sufficient time to administer the contract and to ensure the applicant provided factual information in its application. Western anticipates that a 3-year record retention policy will have little impact on most businesses in the power industry who will keep the APD as part of their normal business records. The procedure and process for the allocation of power shall be the subject matter of a separate notice and is outside the scope of this process.

F. Does the collection indicate the retention period for any recordkeeping requirements for the respondent?

The APD identifies that there is no recordkeeping requirement for the respondent if it does not receive an allocation of Federal power. It also identifies that applicants who receive an allocation of Federal power must retain the records for 3 years.

G. Does the collection inform the public of the information the public needs to exercise scrutiny concerning the agency need to collect information (the reasons the information is collected, the way it is used, an estimate of the burden, whether the response is voluntary, required to obtain a benefit, or mandatory and a statement that no person is required to respond unless a valid OMB control number is displayed)?

If an entity desires a Federal power allocation from Western, Western needs certain information to determine whether the entity is eligible to receive power. Western has a limited amount of power available. Western uses its discretion in allocating power. In order to use its discretion in allocating power, Western will use the information collected on the application. Western will not accept incomplete applications. Western will work with Native American Tribes and other entities that may need assistance in completing the application. No person is required to submit any information unless a valid OMB control number is displayed. No person is required to submit any information unless they desire a Federal power allocation.

H. Is the collection developed by an office that has planned and allocated resources for the efficient and effective management and use of the information collected?

Western's power marketing offices will administer and evaluate the applications. Use and management of the collected information has been factored into each office's functions and resource requirements. Historically, Western has requested the same relative information from applicants and effectively used Western resources to utilize and manage the information in its determinations. Each power marketing office will make a recommendation to Western's Administrator on which applicant(s) should be awarded a Federal power allocation based on the information contained in the APD. Western's Administrator shall use his discretion in the final power allocations. The procedure and process for the allocation of power shall be the subject matter of a separate notice and is outside the scope of this process.

I. Does the collection use effective and efficient statistical survey methods?

Since the information collected is used to determine whether an applicant receives an allocation of Federal power, this section is inapplicable.

J. Does the collection use information technology to the maximum extent practicable to reduce the burden and to improve data quality, agency efficiency, and responsiveness to the public?

The APD will be accessible for downloading via Western's Web site. Western will accept electronic-mail submission of the APD, as well as submission via fax or regular mail. At this time, applicants cannot enter the information on Western's Web site; however, Western is in the process of developing an online form.

VII. Invitation for Comments

Western invites public comment on its request to extend its APD that Western submitted to OMB pursuant to the Paperwork Reduction Act of 1995. The Paperwork Reduction Act requires OMB to make a decision on the ICR within 60 days after this publication or receipt of the proposed collection of information, whichever is later.[22] Comments should be sent directly to the addresses listed in the **ADDRESSES** section above.

Issued in Lakewood, CO on *August 4, 2011.*

Timothy J. Meeks,

Administrator.

[FR Doc. 2011–20400 Filed 8–10–11; 8:45 am]

BILLING CODE 6450–01–P

[22] *See* 5 CFR 1320.10(b).

FEDERAL RESERVE SYSTEM

Proposed Agency Information Collection Activities; Comment Request

AGENCY: Board of Governors of the Federal Reserve System.

SUMMARY: *Background.* On June 15, 1984, the Office of Management and Budget (OMB) delegated to the Board of Governors of the Federal Reserve System (Board) its approval authority under the Paperwork Reduction Act (PRA), as per 5 CFR 1320.16, to approve of and assign OMB control numbers to collection of information requests and requirements conducted or sponsored by the Board under conditions set forth in 5 CFR 1320 Appendix A.1. Board-approved collections of information are incorporated into the official OMB inventory of currently approved collections of information. Copies of the Paperwork Reduction Act Submission, supporting statements and approved collection of information instruments are placed into OMB's public docket files. The Federal Reserve may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

Request for Comment on Information Collection Proposal

The following information collection, which is being handled under this delegated authority, has received initial Board approval and is hereby published for comment. At the end of the comment period, the proposed information collection, along with an analysis of comments and recommendations received, will be submitted to the Board for final approval under OMB delegated authority. Comments are invited on the following:

a. Whether the proposed collection of information is necessary for the proper performance of the Federal Reserve's functions; including whether the information has practical utility;

b. The accuracy of the Federal Reserve's estimate of the burden of the proposed information collection, including the validity of the methodology and assumptions used;

c. Ways to enhance the quality, utility, and clarity of the information to be collected; and

d. Ways to minimize the burden of information collection on respondents, including through the use of automated collection techniques or other forms of information technology.

DATES: Comments must be submitted on or before October 11, 2011.

ADDRESSES: You may submit comments, identified by FR Y–10, FR Y–10E, FR Y–6, and FR Y–7, by any of the following methods:

- *Agency Web Site: http://www.federalreserve.gov.* Follow the instructions for submitting comments at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm.*
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail: regs.comments@federalreserve.gov.* Include docket number in the subject line of the message.
- *Fax:* 202/452–3819 or 202/452–3102.
- *Mail:* Jennifer J. Johnson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue, NW., Washington, DC 20551.

All public comments are available from the Board's Web site at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm* as submitted, unless modified for technical reasons. Accordingly, your comments will not be edited to remove any identifying or contact information. Public comments may also be viewed electronically or in paper form in Room MP–500 of the Board's Martin Building (20th and C Streets, NW.) between 9 a.m. and 5 p.m. on weekdays.

Additionally, commenters should send a copy of their comments to the OMB Desk Officer by mail to the Office of Information and Regulatory Affairs, U.S. Office of Management and Budget, New Executive Office Building, Room 10235, 725 17th Street, NW., Washington, DC 20503 or by fax to 202–395–6974.

FOR FURTHER INFORMATION CONTACT: A copy of the PRA OMB submission, including the proposed reporting form and instructions, supporting statement, and other documentation will be placed into OMB's public docket files, once approved. These documents will also be made available on the Federal Reserve Board's public *Web site at: http://www.federalreserve.gov/boarddocs/reportforms/review.cfm* or may be requested from the agency clearance officer, whose name appears below.

Cynthia Ayouch, Acting Federal Reserve Board Clearance Officer (202–452–3829), Division of Research and Statistics, Board of Governors of the Federal Reserve System, Washington, DC 20551. Telecommunications Device for the Deaf (TDD) users may contact (202–263–4869), Board of Governors of the Federal Reserve System, Washington, DC 20551.

Proposal to approve under OMB delegated authority the extension for three years, with revision of the following reports:

Report title: Report of Changes in Organizational Structure, Annual Report of Bank Holding Companies, and Annual Report of Foreign Banking Organizations.

Agency form number: FR Y–10, FR Y–6, and FR Y–7.

OMB control number: 7100–0297.

Frequency: FR Y–10: Event-generated; FR Y–6 and FR Y–7: Annual.

Reporters: Bank holding companies (BHCs), foreign banking organizations (FBOs), state member banks, Edge and agreement corporations, and nationally chartered banks that are not controlled by a BHC.

Estimated annual reporting hours: FR Y–10: 17,850 hours; FR Y–6: 26,507 hours; FR Y–7: 694 hours.

Estimated average hours per response FR Y–10: 1.75 hours; FR Y–6: 5.25 hours; FR Y–7: 3.75 hours.

Number of respondents: FR Y–10: 3,400; FR Y–6: 5,049; FR Y–7: 185.

General description of report: These information collections are mandatory under the Federal Reserve Act, the Bank Holding Company Act (BHC Act), and the International Banking Act (12 U.S.C. 248 (a)(1), 321, 601, 602, 611a, 615, 625, 1843(k), 1844(c)(1)(A), 3106(a), and 3108(a)), and Regulations K and Y (12 CFR 211.13(c), 225.5(b) and 225.87). Individual respondent data are not considered confidential. However, respondents may request confidential treatment for any information that they believe is subject to an exemption from disclosure under the Freedom of Information Act (FOIA), 5 U.S.C. 552(b).

Abstract: The FR Y–10 is an event generated information collection submitted by FBOs; top-tier BHCs; state member banks unaffiliated with a BHC; Edge and agreement corporations that are not controlled by a state member bank, a domestic BHC, or an FBO; and nationally chartered banks that are not controlled by a BHC (with regard to their foreign investments only), to capture changes in their regulated investments and activities. The Federal Reserve uses the data to monitor structure information on subsidiaries and regulated investments of these entities engaged in banking and nonbanking activities. The FR Y–6 is an annual information collection submitted by top-tier BHCs and nonqualifying FBOs. It collects financial data, an organization chart, verification of domestic branch data, and information about shareholders. The Federal Reserve uses the data to monitor holding company operations and determine holding company compliance with the provisions of the BHC Act and Regulation Y (12 CFR 225). The FR Y–7 is an annual information collection submitted by qualifying FBOs to update their financial and organizational information with the Federal Reserve. The Federal Reserve uses information to assess an FBO's ability to be a continuing source of strength to its U.S. operations and to determine compliance with U.S. laws and regulations.

Current Actions: The Federal Reserve proposes to revise the FR Y–10 reporting forms and instructions by (1) Adding the state and country of incorporation, (2) adding a new business organization type for limited liability limited partnership, (3) adding a check box to report whether ownership is in the form of a general partner or limited partner, (4) adding event types to the 4(k) schedule, (5) requiring the reporting of the representative office when there are no other reportable offices in the United States, and (6) incorporating several instructional clarifications.

The Federal Reserve proposes to revise the FR Y–6 reporting instructions by (1) Clarifying the language regarding confidentiality of the reporter's submission, (2) revising the organizational chart to include information on physical address, state and country of incorporation, and general and limited partners, (3) adding the rounding definition from the FR Y–10 to ensure the reporting of percentage ownership is consistent across all structure reporting forms, (4) modifying the language for securities holders to include persons working in concert, including families, and (5) revising the insiders information to include options, warrants, or other securities as reportable voting securities and to include families in the definition of a principal securities holder.

The Federal Reserve proposes to revise the FR Y–7 reporting form and instructions by (1) Clarifying the language regarding confidentiality of the reporter's submission, (2) revising the organizational chart to include information on physical address and general and limited partners, (3) adding a box to the report form to indicate whether the Annual Report to Shareholders is included in the submission of the FR Y–7, (4) requiring the reporting of the representative office when there are no other reportable offices in the United States, and (5) providing confidential treatment for street addresses of securities holders who are individuals.

The proposed changes to the FR Y–6 and FR Y–7 reporting form and instructions would be effective December 31, 2011. The proposed changes to the FR Y–10 reporting form and instructions would be effective January 1, 2012.

Proposal to approve under OMB delegated authority the extension for three years, without revision of the following report:

Report title: Supplement to the Report of Changes in Organizational Structure.

Agency form number: FR Y–10E.

OMB control number: 7100–0297.

Frequency: Event-generated.

Reporters: BHCs, FBOs, state member banks, Edge and agreement corporations, and nationally chartered banks that are not controlled by a BHC.

Estimated annual reporting hours: 1,700 hours.

Estimated average hours per response: 0.50 hours.

Number of respondents: 3,400.

General description of report: This information collection is mandatory under the Federal Reserve Act, the Bank Holding Company Act (BHC Act), and the International Banking Act (12 U.S.C. 248(a)(1), 321, 601, 602, 611a, 615, and 625, 1843(k), 1844(c)(1)(A), 3106(a)) and Regulation K and Y (12 CFR 211.13(c), 225.5(b) and 225.87). Individual respondent data are not considered confidential. However, respondents may request confidential treatment for any information that they believe is subject to an exemption from disclosure under the Freedom of Information Act(FOIA), 5 U.S.C. 552(b).

Abstract: The FR Y–10E is a free-form supplement that may be used to collect additional structural information deemed to be critical and needed in an expedited manner.

Board of Governors of the Federal Reserve System, August 5, 2011.

Jennifer J. Johnson,

Secretary of the Board.

[FR Doc. 2011–20360 Filed 8–10–11; 8:45 am]

BILLING CODE 6210–01–P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisitions of Shares of a Bank or Bank Holding Company

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire shares of a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. The notices also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than August 26, 2011.

A. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414:

1. *Michael L. Peterson, and* Michael L. Peterson, both of Cedar Falls, Iowa; to acquire additional voting shares of

Community National Bancorporation, Waterloo, Iowa, and thereby indirectly acquire additional voting shares of Community National Bank, Waterloo, Iowa, and Community Bank, Austin, Minnesota.

Board of Governors of the Federal Reserve System, August 8, 2011.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. 2011–20407 Filed 8–10–11; 8:45 am]

BILLING CODE 6210–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Request for Nominations of Candidates To Serve on the Advisory Committee on Immunization Practices (ACIP)

The Centers for Disease Control and Prevention (CDC) is soliciting nominations for membership on the ACIP. The ACIP consists of 15 experts in fields associated with immunization, who are selected by the Secretary of the U.S. Department of Health and Human Services to provide advice and guidance to the Secretary, the Assistant Secretary for Health, and the CDC on the control of vaccine-preventable diseases. The role of the ACIP is to provide advice that will lead to a reduction in the incidence of vaccine preventable diseases in the United States, and an increase in the safe use of vaccines and related biological products. The committee also establishes, reviews, and as appropriate, revises the list of vaccines for administration to children eligible to receive vaccines through the Vaccines for Children (VFC) Program.

Nominations are being sought for individuals who have expertise and qualifications necessary to contribute to the accomplishments of the committee's objectives. Nominees will be selected based on expertise in the field of immunization practices; multi-disciplinary expertise in public health; expertise in the use of vaccines and immunologic agents in both clinical and preventive medicine; knowledge of vaccine development, evaluation, and vaccine delivery; or knowledge about consumer perspectives and/or social and community aspects of immunization programs. Federal employees will not be considered for membership. Members may be invited to serve for four-year terms.

The next cycle of selection of candidates will begin in the Fall of 2011, for selection of potential nominees to replace members whose terms will end on June 30, 2012. Selection of members is based on candidates' qualifications to contribute to the accomplishment of ACIP objectives (*http://www.cdc.gov/vaccines/recs/acip*). The U.S. Department of Health and Human Services policy stipulates that committee membership be balanced in terms of professional training and background, points of view represented, and the committee's function. Consideration is given to a broad representation of geographic areas within the U.S., with equitable representation of the sexes, ethnic and racial minorities, and persons with disabilities. Nominees must be U.S. citizens, and cannot be full-time employees of the U.S. Government.

Candidates should submit the following items:

- Current *curriculum vitae,* including complete contact information (telephone numbers, fax number, mailing address, e-mail address)
- At least one letter of recommendation from person(s) not employed by the U.S. Department of Health and Human Services*

The deadline for receipt of all application materials (for consideration for term beginning July 2012) is November 18, 2011. All files must be submitted electronically as email attachments to: Ms. Stephanie Thomas, c/o ACIP Secretariat, Centers for Disease Control and Prevention, 1600 Clifton Road, NE., Mailstop A–27, Atlanta, Georgia 30333, E-mail: *SThomas5@cdc.gov.* Nominations may be submitted by the candidate him- or herself, or by the person/organization recommending the candidate.

* Candidates may submit letter(s) from current HHS employees if they wish, but at least one letter must be submitted by a person not employed by HHS (e.g., CDC, NIH, FDA etc).

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities for both the Centers for Disease Control and Prevention, and the Agency for Toxic Substances and Disease Registry.

Dated: August 3, 2011.

Elaine L. Baker,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2011–20479 Filed 8–10–11; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Disease, Disability, and Injury Prevention and Control Special Emphasis Panel (SEP): Initial Review

The meeting announced below concerns Special Interest Project (SIP), Systematic Review of Effective Community-based Interventions of Clinical Preventive Services for Older Adults, SIP11–045, initial review.

In accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the aforementioned meeting:

Time and Date: 12 a.m.–2 p.m., August 31, 2011 (Closed).

Place: Teleconference.

Status: The meeting will be closed to the public in accordance with provisions set forth in Section 552b(c) (4) and (6), Title 5 U.S.C., and the Determination of the Director, Management Analysis and Services Office, CDC, pursuant to Public Law 92–463.

Matters to be Discussed: The meeting will include the initial review, discussion, and evaluation of "Systematic Review of Effective Community-based Interventions of Clinical Preventive Services for Older Adults, SIP11–045, initial review."

Contact Person for More Information: Robin Hamre, M.P.H., R.D., Scientific Review Officer, Extramural Research Program Office, National Center for Chronic Disease Prevention and Health Promotion, CDC, 4770 Buford Highway, NE., Mailstop K–92, *RWH9@cdc.gov.*

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Dated: August 5, 2011.

Elizabeth Millington,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2011–20473 Filed 8–10–11; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2010–D–0426]

Guidance for Industry: Bar Code Label Requirements—Questions and Answers; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a document entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers'' dated August 2011. The guidance announced in this notice amends the October 2006 guidance document of the same title by incorporating a revised response to question 12 (Q12). The revised response concerns the ability of vaccine manufacturers to use alternative coding technologies to the linear bar code requirement. The guidance announced in this notice finalizes the draft guidance entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers (Question 12 Update)'' dated August 2010, and is superseding the guidance entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers'' dated October 2006.

DATES: Submit either electronic or written comments on Agency guidances at any time.

ADDRESSES: Submit written requests for single copies of the guidance to the Office of Communication, Outreach and Development (HFM–40), Center for Biologics Evaluation and Research (CBER), Food and Drug Administration, 1401 Rockville Pike, suite 200N, Rockville, MD 20852–1448. Send one self-addressed adhesive label to assist the office in processing your requests. The guidance may also be obtained by mail by calling CBER at 1–800–835–4709 or 301–827–1800. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the guidance document.

Submit electronic comments on the guidance to *http://www.regulations.gov*. Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Benjamin A. Chacko, Center for Biologics Evaluation and Research (HFM–17), Food and Drug Administration, 1401 Rockville Pike, suite 200N, Rockville, MD 20852–1448, 301–827–6210.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a document entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers'' dated August 2011. In the **Federal Register** of February 26, 2004 (69 FR 9120), FDA published a final rule (the February 2004 final rule) requiring certain human drug and biological products to have on their labels a linear bar code that contains, at a minimum, the drug's national drug code number (§ 201.25 (21 CFR 201.25)). To explain how the bar code label requirements apply to specific products or circumstances, in the **Federal Register** of April 27, 2006 (71 FR 24856), FDA announced the availability of a guidance entitled ''Guidance for Industry: Bar Code Label Requirement—Questions and Answers'' that was revised several months later, as discussed in the **Federal Register** of October 5, 2006 (71 FR 58739). Since then, FDA has received additional information concerning vaccines and the linear bar code requirement. In light of this information, we are incorporating a new response to question 12 in the guidance document entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers''. We are providing a revised response to manufacturers of licensed vaccines in connection with the use of alternative coding technologies because it has become increasingly clear that vaccines present unique concerns in the bar coding context, particularly with respect to compliance with recordkeeping and mandatory adverse event reporting requirements that are specific to the administration of childhood vaccines. These concerns are particularly important because vaccines are typically administered in an office or clinic which may have limited administrative support. For example, health care providers who administer a vaccine that is subject to the requirements in the National Childhood Vaccine Injury Act of 1986 (Pub. L. 99–660) (42 U.S.C. 300aa–25(a))) (NCVIA) are required to ensure that there is recorded in the vaccine recipient's permanent medical record (or in a permanent office log or file) the date the vaccine was administered, the manufacturer, lot number of the vaccine, and the name, address, and title of the person administering the vaccine (42 U.S.C. 300aa–25(a)). Manual data entry of this information requires rigorous procedures to ensure accurate records as not all of this information is encoded and clerical recording errors can diminish the value of information available for mandatory adverse event reporting. Furthermore, inaccurate recording of a lot number may delay or misdirect FDA's investigation of an adverse event. At this time, FDA believes that two dimensional symbology technology has advanced such that health care providers may wish to invest in the technology to capture information from a two dimensional code because, through use of this technology, they may more effectively be able to address the reporting requirements reflected in NCVIA.

FDA also believes that enhanced compliance with NCVIA will in turn enable compliance with the mandatory reporting of adverse events by health care providers under the Vaccine Adverse Event Reporting System (VAERS), administered jointly by the Centers for Disease Control and Prevention and FDA. For example, complete automatic entry of vaccine information would facilitate accurate reporting to VAERS, decrease incorrect VAERS entries, and would facilitate rapid, accurate entry into immunization registries. Finally, the ready availability of information in machine readable format will enable more efficient electronic recordation of information, including lot number and vaccine expiration dates.

For these reasons, FDA now will consider requests from vaccine manufacturers who request to use alternate coding technologies, such as two dimensional symbology, that encode lot number and expiration date information, for an exemption under § 201.25(d)(1)(ii) to the linear bar code requirement. In particular, the Agency will consider granting such an exemption request under § 201.25(d)(1)(ii) on the grounds that an alternative regulatory program, comprised of alternative technology such as two dimensional symbology used to facilitate compliance with requirements of public health programs applicable to childhood vaccines, could render the use of linear bar codes unnecessary for patient safety, and we would consider granting a request for an exemption to the bar code requirement under § 201.25(d)(1)(ii) in connection with such use. FDA recognizes that it may be infeasible for a vaccine manufacturer to implement alternate coding technology only for childhood vaccines that are subject to NCVIA, while retaining linear bar coding for its other vaccines due to practical considerations related to manufacturing and cost. Moreover, the schedule of vaccines subject to NCVIA is not static and is updated regularly. The Agency therefore will consider a vaccine manufacturer's request for an exemption to the linear bar code requirement for any of its other licensed vaccines in addition to childhood vaccines.

Note that, as FDA stated in the preamble to the final rule, the Agency continues to emphasize that the general exemption provision in § 201.25(d)(1)(ii) is intended to be used in rare cases (69 FR 9120 at 9131). FDA believes that its revised response to Q12 is consistent with that view because it is narrowly tailored. Further, as alternative technologies continue to advance, the Agency intends to assess these technologies in relation to current bar coding practices and other FDA initiatives, such as efforts to further enhance the security of the drug supply chain through use of a standardized numerical identifier for uniquely identifying prescription drug packages, and the establishment of a unique device identification system for medical devices.

In the **Federal Register** of September 7, 2010 (75 FR 54347), FDA announced the availability of a draft guidance entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers (Question 12 Update)'' dated August 2010. FDA received several comments on the draft guidance and those comments were considered as the guidance was finalized. The guidance announced in this notice finalizes the draft guidance dated August 2010 and incorporates a revised response to question 12 into the guidance entitled ''Guidance for Industry: Bar Code Label Requirements—Questions and Answers''. In addition, editorial changes were made to the guidance to improve clarity.

The guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The guidance represents FDA's current thinking on this topic. It does not create or confer any rights for or on any person and does not operate to bind FDA or the public. An alternative approach may be used if such approach satisfies the requirements of the applicable statutes and regulations.

II. Paperwork Reduction Act of 1995

The guidance refers to previously approved collections of information found in FDA regulations. The collection of information in part 201 has been approved under OMB control number 0910–0537.

III. Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) either electronic or written comments regarding this document. It is only necessary to send one set of comments. It is no longer necessary to send two copies of mailed comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

IV. Electronic Access

Persons with access to the Internet may obtain the guidance at either *http://www.fda.gov/BiologicsBloodVaccines/GuidanceComplianceRegulatoryInformation/Guidances/default.htm* or *http://www.regulations.gov.*

Dated: August 4, 2011.

Leslie Kux,

Acting Assistant Commissioner for Policy.

[FR Doc. 2011–20385 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2009–D–0324]

International Conference on Harmonisation; Guidance on E16 Biomarkers Related to Drug or Biotechnology Product Development: Context, Structure, and Format of Qualification Submissions; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a guidance entitled ''E16 Biomarkers Related to Drug or Biotechnology Product Development: Context, Structure, and Format of Qualification Submissions.'' The guidance was prepared under the auspices of the International Conference on Harmonisation of Technical Requirements for Registration of Pharmaceuticals for Human Use (ICH). The guidance describes recommendations regarding the context, structure, and format of qualification submissions for clinical and nonclinical genomic biomarkers related to development of drug or biotechnology products, including translational medicine approaches, pharmacokinetics, pharmacodynamics, and efficacy and safety aspects. The guidance is intended to create a harmonized recommended structure for biomarker qualification applications that will foster consistency of applications across regions and facilitate discussions with and among regulatory authorities.

DATES: Submit either electronic or written comments on Agency guidances at any time.

ADDRESSES: Submit written requests for single copies of the guidance to the Division of Drug Information (HFD–240), Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, rm. 2201, Silver Spring, MD 20993–0002, or the Office of Communication, Outreach and Development (HFM–40), Center for Biologics Evaluation and Research (CBER), Food and Drug Administration, 1401 Rockville Pike, Rockville, MD 20852–1448. Send one self-addressed adhesive label to assist the office in processing your requests. The guidance may also be obtained by mail by calling CBER at 1–800–835–4709 or 301–827–1800. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the guidance document.

Submit electronic comments on the guidance to *http://www.regulations.gov.* Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT:

Regarding the guidance:

Federico Goodsaid, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, rm. 2148, Silver Spring, MD 20903–0002, 301–796–1535; or

Jennifer Catalano, Center for Biologics and Evaluation Research (HFM–735), Food and Drug Administration, 1401 Rockville Pike, suite 200N, Rockville, MD 20852–1448, 301–827–0706.

Regarding the ICH:

Michelle Limoli, Office of International Programs (HFG–1), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–827–4480.

SUPPLEMENTARY INFORMATION:

I. Background

In recent years, many important initiatives have been undertaken by regulatory authorities and industry associations to promote international harmonization of regulatory requirements. FDA has participated in many meetings designed to enhance harmonization and is committed to seeking scientifically based harmonized technical procedures for pharmaceutical development. One of the goals of harmonization is to identify and then reduce differences in technical requirements for drug development among regulatory agencies.

ICH was organized to provide an opportunity for tripartite harmonization initiatives to be developed with input from both regulatory and industry representatives. FDA also seeks input from consumer representatives and others. ICH is concerned with harmonization of technical requirements for the registration of pharmaceutical products among three regions: The European Union, Japan, and the United States. The six ICH sponsors are the European Commission; the European Federation of Pharmaceutical Industries Associations; the Japanese Ministry of Health, Labour, and Welfare; the Japanese Pharmaceutical Manufacturers Association; the Centers for Drug Evaluation and Research and Biologics Evaluation and Research, FDA; and the Pharmaceutical Research and Manufacturers of America. The ICH Secretariat, which coordinates the preparation of documentation, is provided by the International Federation of Pharmaceutical Manufacturers Associations (IFPMA).

The ICH Steering Committee includes representatives from each of the ICH sponsors and the IFPMA, as well as observers from the World Health Organization, Health Canada, and the European Free Trade Area.

In the **Federal Register** of July 30, 2009 (74 FR 38033), FDA published a notice announcing the availability of a draft guidance entitled ''E16 Genomic Biomarkers Related to Drug Response: Context, Structure, and Format of Qualification Submissions.'' The notice gave interested persons an opportunity to submit comments by September 28, 2009.

After consideration of the comments received and revisions to the guidance, a final draft of the guidance was submitted to the ICH Steering Committee and endorsed by the three participating regulatory agencies in September 2010.

The guidance provides recommendations on the context, structure, and format of qualification submissions as follows:

- The proposed context of use of a biomarker corresponds to the data supporting its qualification. The context of use of a biomarker in a biomarker qualification can be narrow or broad—the biomarker(s) might be useful for only a single drug or biotechnology product, for several drug or biotechnology products in a drug class, or even across several drug classes.
- The structure of the submission should be consistent regardless of the context proposed and flexible enough to deal with the specific attributes of each submission. In addition, use of the recommended structure should facilitate submission and review of future biomarker qualification submissions expanding the use of the biomarker to new contexts, as would be the case if, for example, a nonclinical context of use expands to a clinical context of use.
- The format of the data for qualifying a biomarker can vary significantly depending on the context. The format should support an evaluation of the data and can include reports, tabulations, and raw data (if requested by regulatory authorities according to the relevant practices in place).

The application structure described in this guidance is intended for biomarker qualification submissions after sufficient supporting data have been generated. However, this structure can also be considered for submissions intended to obtain scientific advice from regulatory authorities before or during the generation of the biomarker data intended to support qualification.

This guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The guidance represents the Agency's current thinking on this topic. It does not create or confer any rights for or on any person and does not operate to bind FDA or the public. An alternative approach may be used if such approach satisfies the requirements of the applicable statutes and regulations.

II. Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) either electronic or written comments regarding this document. It is only necessary to send one set of comments. It is no longer necessary to send two copies of mailed comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

III. Electronic Access

Persons with access to the Internet may obtain the document at *http://www.regulations.gov, http://www.fda.gov/Drugs/GuidanceComplianceRegulatoryInformation/Guidances/default.htm,* or *http://www.fda.gov/BiologicsBloodVaccines/GuidanceComplianceRegulatoryInformation/Guidances/default.htm.*

Dated: August 4, 2011.

Leslie Kux,

Acting Assistant Commissioner for Policy.

[FR Doc. 2011–20386 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0002]

Cellular, Tissue and Gene Therapies Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of a public advisory committee of the Food and Drug Administration (FDA). The meeting will be open to the public.

Name of Committee: Cellular, Tissue and Gene Therapies Advisory Committee.

General Function of the Committee: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on September 22 and 23, 2011, from 8 a.m. to 5 p.m.

Location: Hilton Hotel, Washington, DC North/Gaithersburg, 620 Perry Pkwy., Gaithersburg, MD 20977, 301–977–8900. For those unable to attend in person, the meeting will also be available by Web cast. On September 22, 2011, the link for the Web cast is available at *http://fda.yorkcast.com/webcast/Viewer/?peid=637f14248dca4236a5f9a3b622e6501e1d.* On September 23, 2011, the link for the Web cast is available at *http://fda.yorkcast.com/webcast/Viewer/?peid=2e8b3eb7638d42ca9652c328a854efb51d.*

Contact Person: Gail Dapolito or Sheryl Clark (HFM–71), Center for Biologics Evaluation and Research, Food and Drug Administration, 1401 Rockville Pike, Rockville, MD 20853, 301–827–0314, or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area), and follow the prompts to the desired center or product area. Please call the Information Line for up-to-date information on this meeting. A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site and call the appropriate advisory committee hot line/phone line to learn about possible modifications before coming to the meeting.

Agenda: On September 22, 2011, the committee will discuss BLA 125397, Umbilical Cord Blood, New York Blood Center, indicated for hematologic malignancies, bone marrow failure, primary immunodeficiency diseases, beta thalassemia, Hurler syndrome, Krabbe disease, and X-linked adrenoleukodystrophy. On September 23, 2011, the Committee will discuss HDE BH110018, CliniMACS CD34 Selection System, Miltenyi Biotec, for processing allogeneic HLA-matched hematopoietic progenitor cells-apheresis (HPC–C) from a related donor to obtain a CD34$^+$ Cell population intended for hematopoietic reconstitution following a Myeloablative preparative regimen without the need for additional graft-vs-host disease (GVHD) prophylaxis in patients with acute myelogenous leukemia in first or second morphologic complete remission.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before September 15, 2011. Oral presentations from the public will be scheduled on September 22, 2011, between approximately 11 a.m. and 12 noon and on September 23, 2011, between approximately 11:30 a.m. and 12:30 p.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before September 7, 2011. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by September 8, 2011.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Gail Dapolito at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: August 8, 2011.

Leslie Kux,

Acting Assistant Commissioner for Policy.

[FR Doc. 2011–20399 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0002]

Food and Drug Administration/National Heart, Lung, and Blood Institute/National Science Foundation Public Workshop on Computer Methods for Medical Devices

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of public workshop.

SUMMARY: The Food and Drug Administration (FDA) is announcing a public workshop entitled ''FDA/NHLBI/NSF Workshop on Computer Methods for Medical Devices.'' FDA is cosponsoring the conference workshop with the National Heart, Lung, and Blood Institute (NHLBI) of the National Institutes of Health and the National Science Foundation (NSF). The purpose of the workshop is to facilitate discussion between FDA and other interested parties on the use of computational modeling in the design, development and evaluation of medical devices.

Dates and Times: The public workshop will be held on September 7, 8, and 9, 2011, from 9 a.m. to 5 p.m. An optional FDA Microstructure Modeling session will be held from 1 to 5 p.m. on September 6, 2011. Participants are encouraged to arrive early to ensure time for parking and security screening before the meeting. Security screening will begin at 8 a.m. Persons interested in attending this public workshop must register by 5 p.m. on August 30, 2011.

Location: The public workshop and optional session will be held at the FDA White Oak Campus, 10903 New Hampshire Ave, Building 31 Conference Center, the Great Room (rm. 1503), Silver Spring, MD 20993–0002.

Contact Persons: Donna R. Lochner, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 62, rm. 3220, Silver Spring, MD 20993–0002, 301–796–6309, *e-mail: donna.lochner@fda.hhs.gov;* or

Tina M. Morrison, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, rm. 1272, Silver Spring, MD 20993–0002, 301–796–6310, *e-mail: tina.morrison@fda.hhs.gov.*

Registration: To register for the public workshop and optional session, please visit the following Web site: *http://www.fda.gov/MedicalDevices/NewsEvents/WorkshopsConferences/default.htm* (or go to *http://www.fda.gov* and select the FDA Medical Devices News & Events—Workshops & Conferences calendar and select this public workshop from the posted events list). Please provide complete contact information for each attendee, including name, title, affiliation, address, email, and telephone number. For those without Internet access, please call the contact person to register. Registration is mandatory as space is limited and onsite registration will not be available. FDA may limit the number of participants from each organization. There is no registration fee for the public workshop.

Registrants requesting to present written materials or to make oral presentations at the public workshop, please call the contact persons by August 23, 2011.

If you need special accommodations because of a disability, please contact Susan Monahan, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, rm. 4321, Silver Spring, MD 20993–0002, 301–796–5661 at least 7 days before the public workshop.

SUPPLEMENTARY INFORMATION:

I. Why are we holding this public workshop?

The purpose of the public workshop is to facilitate discussion between FDA and other interested parties on the use of computational modeling in medical device design, development and evaluation.

II. What are the topics we intend to address at the public workshop?

We hope to discuss a large number of issues at the public workshop, with our overall theme being the validation of computer models with nonclinical models. Topics include, but are not limited to the following:

- Advancing Computational Modeling Studies—how is computational modeling being used for device design, development, and/or evaluation?
- Best Validation Practices—what validation scheme has worked for computational model systems?
- Lessons Learned—what validation schemes have been unsuccessful for computational model systems?
- Data Resources—where are data for boundary conditions, loading conditions, material properties, etc. obtained for model systems?

III. Where can I find out more about this public workshop?

Background information on the public workshop, registration information, the agenda, information about lodging, food services, and other relevant information will be posted, as it becomes available, on the Internet at: *http://www.fda.gov/MedicalDevices/NewsEvents/WorkshopsConferences/default.htm* (or go to *http://www.fda.gov* and select the FDA Medical Devices News & Events—Workshops & Conferences calendar and select this public workshop from the posted events list).

Dated *August 8, 2011.*

Nancy K. Stade,

Deputy Director for Policy, Center for Devices and Radiological Health.

[FR Doc. 2011–20446 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0002]

The Development and Evaluation of Next-Generation Smallpox Vaccines; Public Workshop

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of public workshop.

The Food and Drug Administration (FDA) Center for Biologics Evaluation and Research (CBER) and the National Institutes of Health, the National Institute of Allergy and Infectious Diseases are announcing a public workshop entitled ''The Development and Evaluation of Next-Generation Smallpox Vaccines.'' The purpose of the public workshop is to identify and discuss the key issues related to the development and evaluation of next-generation smallpox vaccines. The public workshop will include presentations on the human response to smallpox vaccines and development of animal models for demonstration of effectiveness of next-generation smallpox vaccines.

Date and Time: The public workshop will be held on September 16, 2011, from 8 a.m. to 5:30 p.m.

Location: The public workshop will be held at the Hilton Washington DC North/Gaithersburg, 620 Perry Pkwy., Gaithersburg, MD 20877.

Contact Person: Bernadette Williamson-Taylor, Center for Biologics Evaluation and Research (HFM–43), Food and Drug Administration, 1401 Rockville Pike, suite 200N, Rockville, MD 20852–1448, 301–827–2000, *Fax:* 301–827–3079, *e-mail: CBERTraining@fda.hhs.gov* (in the subject line type ''Smallpox Workshop'').

Registration: Mail, fax, or email your registration information (including name, title, firm name, address, telephone, and fax numbers) to the contact person by August 23, 2011. There is no registration fee for the public workshop. Early registration is recommended because seating is limited. Registration on the day of the public workshop will be provided on a space available basis beginning at 7:30 a.m.

If you need special accommodations due to a disability, please contact Bernadette Williamson-Taylor (see *Contact Person*) at least 7 days in advance.

SUPPLEMENTARY INFORMATION: Smallpox is a serious, highly contagious, and sometimes fatal infectious disease. Although the World Health Organization declared the disease eradicated in 1980, the threat of smallpox as a biological weapon remains. Vaccination is the only prevention for the disease and there are currently no FDA-approved treatments.

First-generation smallpox vaccines were prepared on the skin of calves or other animals or in chicken eggs. Although these vaccines were not evaluated for efficacy in well-controlled trials, they were highly effective as evidenced by the successful global eradication of smallpox. Manufacturing of these vaccines has ceased and they are no longer licensed in the United States.

In 2007, FDA licensed the first second-generation smallpox vaccine, ACAM2000. This vaccine is based on a single plaque-purified vaccinia virus derivative of Dryvax (a previously licensed first-generation vaccine) and is aseptically propagated using cell culture technology under modern manufacturing practices and standards. Both ACAM2000 and Dryvax are derived from the New York City Board of Health strain and produce a vesicular or pustular lesion (referred to as a ''vaccine take'') that has been shown to correlate with protection. In clinical trials, ACAM2000 elicited vaccinia-neutralizing antibodies and cell-mediated immune responses, with both clinical and immunological outcomes similar to Dryvax.

Because ACAM2000 may cause serious adverse reactions, there is a desire to develop safer vaccines should there be a need to vaccinate the general population due to a threat of an attack with the smallpox virus. Currently, the next-generation smallpox vaccines under development do not produce the characteristic ''vaccine take.'' In addition, it is not ethical or feasible to evaluate the effectiveness of these vaccines in humans as the natural disease has been eradicated. Therefore, the effectiveness of these next-generation smallpox vaccines may be based on animal efficacy data, if scientifically appropriate, and to comparative human immune response data. As for any biologic product, licensure of new smallpox vaccines requires demonstration of safety, purity, and potency.

The public workshop will: (1) Discuss regulatory challenges and approaches related to the licensure of next-generation smallpox vaccines; (2) discuss the strengths and weaknesses of various animal models relative to their ability to mimic human disease that can be used to predict the effectiveness of next-generation smallpox vaccines in humans; (3) discuss the most appropriate methods to bridge immunogenicity of next-generation smallpox vaccines to licensed smallpox vaccines in clinical trials; and (4) discuss viable methods of extrapolating clinical efficacy of next-generation smallpox vaccines from immunogenicity and efficacy data from relevant animal models.

Transcripts: Transcripts of the public workshop may be requested in writing from the Division of Freedom of Information Office (ELEM–1029), Food and Drug Administration, 12420 Parklawn Dr., Element Bldg., Rockville, MD 20857, approximately 15 working days after the public workshop at a cost of 10 cents per page. A transcript of the public workshop will be available on the Internet at *http://www.fda.gov/BiologicsBloodVaccines/NewsEvents/WorkshopsMeetingsConferences/TranscriptsMinutes/default.htm.*

Dated: August 4, 2011.

Leslie Kux,

Acting Assistant Commissioner for Policy.

[FR Doc. 2011–20367 Filed 8–10–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Government-Owned Inventions; Availability for Licensing

AGENCY: National Institutes of Health, Public Health Service, HHS.

ACTION: Notice.

SUMMARY: The inventions listed below are owned by an agency of the U.S. Government and are available for licensing in the U.S. in accordance with 35 U.S.C. 207 to achieve expeditious commercialization of results of federally-funded research and development. Foreign patent applications are filed on selected inventions to extend market coverage for companies and may also be available for licensing.

ADDRESSES: Licensing information and copies of the U.S. patent applications listed below may be obtained by writing to the indicated licensing contact at the Office of Technology Transfer, National Institutes of Health, 6011 Executive Boulevard, Suite 325, Rockville, Maryland 20852–3804; *telephone:* 301–496–7057; *fax:* 301–402–0220. A signed Confidential Disclosure Agreement will be required to receive copies of the patent applications.

Tumor Markers for Potentially Predicting Outcome of Anti-angiogenesis Therapy

Description of Technology: During the past decade, anti-angiogenesis therapy has evolved as a promising approach to the treatment of cancer. However, a significant fraction of patients do not benefit from anti-angiogenesis therapy, either by itself or in combination with chemotherapy. A significant need remains for a means of predicting clinical benefit from anti-angiogenesis therapy.

Researchers at the National Cancer Institute, NIH, have identified tumor cell apoptosis, p53, and HER2 as having potential predictive significance for treatment outcome in breast cancer patients who received anti-angiogenesis therapy in combination with chemotherapy. The researchers have developed a quantitative antibody-based testing method for correlating expression of p53 and HER2 and tumor apoptosis with clinical outcome. These markers can be potentially applied to predict which patients should receive anti-angiogenesis therapy plus chemotherapy.

Potential Commercial Applications:

• A diagnostic kit for predicting benefit of anti-angiogenesis therapy plus chemotherapy in breast cancer patients.

• A testing service for breast cancer patients.

Competitive Advantages:

• The clinical predictive markers p53, HER2 and tumor apoptosis indicators are easily and readily evaluated using the new assay.

• The new assay is potentially useful to determine which patients should or should not receive anti-angiogenesis therapy plus chemotherapy for longer survival and progression-free survival in patients with breast cancer.

• A study with a large sample size will be planned by the inventors and potential collaborators.

Development Stage:

• Pilot.

• In vivo data available (human).

Inventors: Sherry Yang (NCI), Seth Steinberg (NCI), *et al.*

Publication: Yang S, *et al.* p53, HER2 and tumor cell apoptosis correlate with clinical outcome after neoadjuvant bevacizumab plus chemotherapy in breast cancer. Int J Oncol. 2011 May; 38(5):1445–1452. [PMID 21399868]

Intellectual Property: HHS Reference No. E–096–2011/0—U.S. Patent Application No. 61/448,092 filed 01 March 2011

Licensing Contact: Patrick McCue, Ph.D.; 301–435–5560; mccuepat@mail.nih.gov

Collaborative Research Opportunity: The National Clinical Target Validation Laboratory, DCTD, NCI, NIH, is seeking statements of capability or interest from parties interested in collaborative research to further develop, evaluate, or commercialize p53, tumor apoptosis, and HER2 as markers for anti-angiogenesis therapy. For collaboration opportunities, please contact John Hewes, Ph.D. at *hewesj@mail.nih.gov.*

TRRAP and GRIN2A Mutations for the Diagnosis and Treatment of Melanoma

Description of Technology: Using whole-exome sequencing of matched normal and metastatic tumor DNAs, researchers at the NIH have identified several novel somatic (*e.g.,* tumor-specific) alterations, many of which have not previously been known to be genetically altered in tumors or linked to melanoma. In particular, the researchers identified a recurrent ''hotspot'' mutation in the transformation/transcription domain-associated protein (TRRAP) gene, found the glutamate receptor ionotropic N-methyl D-aspartate 2A (GRIN2A) gene as a highly mutated in melanoma, and have shown that the majority of melanoma tumors have alterations in genes encoding members of the glutamate signaling pathway. Therefore, this technology not only provides a comprehensive map of genetic alterations in melanoma, but has important diagnostic and therapeutic applications. Mutations in the TRRAP and GRIN2A genes can be used as diagnostic markers for melanoma and may serve as therapeutic targets in the treatment of melanoma. In addition, glutamate antagonists have previously been shown to inhibit proliferation of human tumor cells, and therefore further investigation of the pathway in melanoma could allow for the identification of new therapeutic proteins that target this pathway.

Potential Commercial Applications:

• Diagnostic array for the detection of TRRAP and GRIN2A mutations.

• Method of identifying TRRAP and GRIN2A inhibitors as therapeutic agents to treat malignant melanoma patients.

• Method of selecting a therapy based on the presence of TRRAP and GRIN2A mutations.

Competitive Advantages:

• Complete analysis of melanoma exome alterations.

• TRRAP, GRIN2A, and the other identified mutations are highly frequent and/or highly mutated in melanomas.

• Glutamate antagonists have already been shown to inhibit tumor growth. Thus, this technology may prove useful for the development of novel diagnostic tests and therapeutics.

Development Stage: Pre-clinical.

Inventors: Yardena Samuels and Xiaomu Wei (NHGRI).

Publication: Wei X, et al. Exome sequencing identifies GRIN2A as frequently mutated in melanoma. Nat Genet. 2011 May;43(5):442–446. [PMID: 21499247].

Intellectual Property:

• HHS Reference No. E–013–2011/0—U.S. Provisional Application No. 61/462,471 filed 02 February 2011.

• Research Tool—Patent protection is not being pursued for the TRRAP and GRIN2A melanoma metastatic cell lines.

Related Technologies:

• HHS Reference No. E–272–2008/0—U.S. Patent Application No. 13/128,125 filed 06 May 2011, European and Australian applications filed; Mutations of the ERBB4 Gene in Melanoma.

• HHS Reference No. E–229–2010/0—Research Tool; ERBB4 Mutations Identified in Human Melanoma Metastasis Cell Lines (2690, 2379, 2197, 2183, 2535, 2645, 1770, 2359, 2238, 2319, 2190).

• HHS Reference No. E–232–2010/0—Research Tool; Isocitrate Dehydrogenase 1 (IDH1) R132 Mutation Human Melanoma Metastasis Cell Line.

Licensing Contact: Whitney Hastings; 301–451–7337; hastingw@mail.nih.gov.

Cells and Nanoparticles With Altered Protein Expression Patterns Useful for the Modulation of T Cell Activity for Immunotherapy

Description of Technology: NIH scientists have developed human cells and nanoparticles to enhance immunotherapy. Specifically, researchers have identified that cells or nanoparticles expressing a high temperature requirement serine peptidase 1 (HtrA1) activator and/or a cytokine-induced Src homology 2 protein (CIS) inhibitor are capable of increasing T cell activity. These compositions can be used primarily in T cell immunotherapy against various cancers and infectious diseases where enhanced T cell activity is beneficial. Conversely, cells or nanoparticles that express a HtrA1 inhibitor and/or a CIS activator can suppress T cell activity. These compositions can be utilized to treat various auto- or alloimmune diseases and can be used to prevent transplant rejections.

HtrA1 (also known as L56, ARMD7, ORF480, and PRSS11) is a serine protease that is known to inhibit the TGF-beta family proteins. CIS (also known as G18, SOCS, CIS–1, and CISH) is a member of the suppression of cytokine signaling (SOCS) family of proteins and inhibit the JAK/STAT signaling pathways. CIS acts to inhibit HtrA1 and repress cell activation targets. Immunotherapy, although an effective treatment strategy, sometimes fails when cells lose activity. T cells adoptively transferred into patients where CIS is inhibited and/or HtrA1 is activated should maintain their activity and lead to more successful adoptive T cell transfers.

Potential Commercial Applications:

• Immunotherapy for cancer or infectious diseases using human cells or nanoparticles expressing an HtrA1 activator and/or a CIS inhibitor

• Therapeutic for treating autoimmune diseases using human cells and or nanoparticles expressing an HtrA1 inhibitor and/or a CIS activator

• Agents expressing an HtrA1 inhibitor and/or a CIS activator to prevent organ, tissue, or cell transplant rejection and treat alloimmune diseases, such as graft-versus-host disease

• Components of a combination therapy to increase or suppress T cell activity in a patient

Competitive Advantages:

• Some patients do not respond to T cell immunotherapy due to lack of cell persistence, survival, or activity as well as for other poorly understood reasons. Modifying HtrA1 and CIS in currently existing T cell immunotherapies should increase the success rate of these therapies by increasing the persistence and survival of the infused cells.

• T cells can become ''exhausted'' as they mature following activation by target antigen. Cells with altered expression of HtrA1 and/or CIS may be able to avoid exhaustion after repeated activation.

Development Stage:

• Pre-clinical.

• In vitro data available.

• In vivo data available (animal).

Inventors: Douglas C. Palmer and Nicholas P. Restifo (NCI).

Publication: Palmer DC and Restifo NP. Suppressors of cytokine signaling (SOCS) in T cell differentiation, maturation, and function. Trends Immunol. 2009 Dec;30(12):592–602. [PMID 19879803].

Intellectual Property: HHS Reference No. E–069–2010/0—U.S. Patent Application No. 61/420,825 filed 08 December 2010.

Licensing Contact: Samuel E. Bish, Ph.D.; 301–435–5282; *bishse@mail.nih.gov*

Dated: August 5, 2011.

Richard U. Rodriguez,

Director, Division of Technology Development and Transfer, Office of Technology Transfer, National Institutes of Health.

[FR Doc. 2011–20447 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health National Institute of Environmental Health Sciences; Notice of Meeting

Pursuant to section 10(a) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Interagency Breast Cancer and Environmental Research Coordinating Committee.

The meeting will be open to the public, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

Name of Committee: Interagency Breast Cancer and Environmental Research Coordinating Committee.

Date: September 26–27, 2011.

Time: 8:30 a.m. to 5 p.m.

Agenda: The purpose of the meeting is to continue the work of the Committee, to share and coordinate information on existing research activities, & make recommendations to NIH & other Federal agencies on how to improve existing research programs related to breast cancer & the environment. The agenda will be posted on the web: *http://www.niehs.nih.gov/about/orgstructure/boards/ibcercc/.*

Place: Nat. Inst. of Environmental Health Sciences, Building 101, Rodbell Auditorium, 111 T. W. Alexander Drive, Research Triangle Park, NC 27709.

Contact Person: Gwen W. Collman, PhD, Director, Division of Extramural Research and Training (DERT), Nat. Inst. of Environmental Health Sciences, National Institutes of Health, 615 Davis Dr., KEY615/3112, Research Triangle Park, NC 27709, (919) 541–4980, *collman@niehs.nih.gov.*

Any member of the public interested in presenting oral comments to the Committee should submit their remarks in writing at least 10 days in advance of the meeting. Comments in document format (*i.e.* WORD, Rich Text, PDF) may be submitted via e-mail to *ibcercc@niehs.nih.gov.* You do not need to attend the meeting in order to submit comments.

Interested individuals and representatives of organizations may submit a letter of intent, a brief description of the organization represented, and a short description of the oral comments you wish to present. Only one representative per organization may be allowed to present oral comments and if accepted by the committee, presentations may be limited to five minutes. Both printed and electronic copies are requested for the record. The statement should include the name, address, telephone number and, when applicable, the business or professional affiliation of the interested person. Oral comments will begin at approximately 2:30 p.m. on Tuesday, September 27, 2011. Although time will not be allotted for comments on Monday, September 26, 2011, members of the public are welcome to attend the entire meeting.

Anyone who wishes to attend the meeting and/or submit comments to the committee is asked to RSVP via e-mail to *ibcercc@niehs.nih.gov.* Comments are delivered to the Contact Person listed on this notice.

(Catalogue of Federal Domestic Assistance Program Nos. 93.115, Biometry and Risk Estimation—Health Risks from Environmental Exposures; 93.142, NIEHS Hazardous Waste Worker Health and Safety Training; 93.143, NIEHS Superfund Hazardous Substances—Basic Research and Education; 93.894, Resources and Manpower Development in the Environmental Health Sciences; 93.113, Biological Response to Environmental Health Hazards; 93.114, Applied Toxicological Research and Testing, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20438 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Library of Medicine; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable materials, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Library of Medicine Special Emphasis Panel, R01/R13/R21 Conflicteds.

Date: September 30, 2011.

Time: 12 p.m. to 2 p.m.

Agenda: To review and evaluate grant applications.

Place: National Library of Medicine, 6705 Rockledge Drive, Suite 301, Bethesda, MD 20817, (Telephone Conference Call).

Contact Person: Zoe H. Huang, MD, Scientific Review Officer, Extramural Programs, National Library of Medicine, NIH, 6705 Rockledge Drive, Suite 301, Bethesda, MD 20892–7968, 301–594–4937, *hungz@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program No. 93.879, Medical Library Assistance, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20439 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Nursing Research Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the National Advisory Council for Nursing Research.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Advisory Council for Nursing Research.

Date: September 20–21, 2011.

Open: September 20, 2011, 1 p.m. to 5 p.m.

Agenda: Discussion of Program Policies and Issues.

Place: National Institutes of Health, Building 31, 31 Center Drive, 6th Floor, C Wing, Room 6, Bethesda, MD 20892.

Closed: September 21, 2011, 9 a.m. to 1 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Building 31, 31 Center Drive, 6th Floor, C Wing, Room 6, Bethesda, MD 20892.

Contact Person: Yvonne E Bryan, PhD, Special Assistant to the Director, National Institute of Nursing, National Institutes of Health, 31 Center Drive, Room 5B–05, Bethesda, MD 20892. 301–594–1580. *bryany@mail.nih.gov.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

In the interest of security, NIH has instituted stringent procedures for entrance onto the NIH campus. All visitor vehicles, including taxicabs, hotel, and airport shuttles will be inspected before being allowed on campus. Visitors will be asked to show one form of identification (for example, a government-issued photo ID, driver's license, or passport) and to state the purpose of their visit.

Information is also available on the Institute's/Center's home page: *http://www.nih.gov/ninr/a_advisory.html,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.361, Nursing Research, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20440 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Center for Scientific Review Special Emphasis Panel, Program Project: Retina Pathology.

Date: September 12, 2011.

Time: 1 to 3:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, (Telephone Conference Call).

Contact Person: Raya Mandler, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5217, MSC 7840, Bethesda, MD 20892, 301–402–8228, *rayam@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Program Project: Integrative Neuroscience.

Date: September 14–15, 2011.

Time: 8 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, (Virtual Meeting).

Contact Person: Brian Hoshaw, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5181, MSC 7844, Bethesda, MD 20892, 301–435–1033, *hoshawb@csr.nih.gov.*

Name of Committee: Brain Disorders and Clinical Neuroscience Integrated Review Group, Chronic Dysfunction and Integrative Neurodegeneration Study Section.

Date: September 19–20, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: The Westin Seattle, 1900 5th Avenue, Seattle, WA 98101.

Contact Person: Kevin Walton, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5200, MSC 7846, Bethesda, MD 20892, 301–435–1785, *kevin.walton@nih.hhs.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Small Business: Neuroscience Education.

Date: September 20–21, 2011.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, (Virtual Meeting).

Contact Person: Jonathan Arias, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5170, MSC 7840, Bethesda, MD 20892, 301–435–2406, *ariasj@csr.nih.gov.*

Name of Committee: Bioengineering Sciences & Technologies Integrated Review Group, Instrumentation and Systems Development Study Section.

Date: September 22–23, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Courtyard by Marriott, 5520 Wisconsin Avenue, Chevy Chase, MD 20815.

Contact Person: Kathryn Kalasinsky, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5158 MSC 7806, Bethesda, MD 20892, 301–402–1074, *kalasinskyks@mail.nih.gov.*

Name of Committee: Oncology 1-Basic Translational Integrated Review Group, Tumor Progression and Metastasis Study Section.

Date: September 22–23, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Westin Long Beach, 333 East Ocean Boulevard, Long Beach, CA 90802.

Contact Person: Rolf Jakobi, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6187, MSC 7806, Bethesda, MD 20892, 301–495–1718, *jakobir@mail.nih.gov.*

Name of Committee: Oncology 2-Translational Clinical Integrated Review Group, Developmental Therapeutics Study Section.

Date: September 22–23, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Embassy Suites DC, 1250 22nd Street, NW., Washington, DC 20037.

Contact Person: Sharon K Gubanich, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6214, MSC 7804, Bethesda, MD 20892, (301) 408–9512, *gubanics@csr.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20441 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Eunice Kennedy Shriver National Institute of Child Health & Human Development; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Child Health and Human Development, Special Emphasis Panel.

NICHD International and Domestic Pediatric and Maternal HIV, Studies Coordinating Center.

Date: September 1, 2011.

Time: 1 p.m. to 5 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institutes of Health, 6100 Executive Boulevard, Rockville, MD 20852, (Telephone Conference Call).

Contact Person: Sathasiva B. Kandasamy, PhD, Scientific Review Officer, Division Of Scientific Review, Eunice Kennedy Shriver National Institute of Child Health and Human Development, NIH, 6100 Executive Blvd., ROOM 5B01, Bethesda, MD 20892, 301–435–6680, *skandasa@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20444 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel, Investigator-Initiated Program Project Grant (P01).

Date: September 7, 2011.

Time: 1 to 5 p.m..

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6700B Rockledge Drive, Bethesda, MD 20817, (Telephone Conference Call).

Contact Person: Brandt R. Burgess, PhD, Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institutes of Health/NIAID, 6700B Rockledge Drive, MSC 7616, Bethdesda, MD 20892–7616, 301–451–2584, *bburgess@niaid.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer S. Spaeth

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20437 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Fogarty International Center Notice of Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Fogarty International Center Advisory Board.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public in accordance with the provisions set forth in section 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the Discussions could disclose confidential trade secrets or commercial property such as patentable materials, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Fogarty International Center Advisory Board.

Date: September 12–13, 2011.

Closed: September 12, 2011, 2 p.m. to 5:30 p.m.

Agenda: To review and evaluate grant applications and/or proposals.

Place: National Institutes of Health, Building 31, 31 Center Drive, C Wing, Room B2C07, Bethesda, MD 20892.

Open: September 13, 2011, 9 a.m. to 3 p.m.

Agenda: Discussion of the role of Fogarty's Division of International Relations and health diplomacy.

Place: National Institutes of Health, Lawton L. Chiles International House, Bethesda, MD 20892.

Contact Person: Robert Eiss, Public Health Advisor, Fogarty International Center, National Institutes of Health, 31 Center Drive, Room B2C02, Bethesda, MD 20892. (301) 496–1415. *EISSR@MAIL.NIH.GOV.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

In the interest of security, NIH has instituted stringent procedures for entrance onto the NIH campus. All visitor vehicles, including taxicabs, hotel, and airport shuttles will be inspected before being allowed on campus. Visitors will be asked to show one form of identification (for example, a government-issued photo ID, driver's license, or passport) and to state the purpose of their visit.

Information is also available on the Institute's/Center's home page: *http://www.nih.gov/fic/about/advisory.html* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.14, Intramural Research Training Award; 93.22, Clinical Research Loan Repayment Program for Individuals from Disadvantaged Backgrounds; 93.232, Loan Repayment Program for Research Generally; 93.39, Academic Research Enhancement Award; 93.936, NIH Acquired Immunodeficiency Syndrome Research Loan Repayment Program; 93.187, Undergraduate Scholarship Program for Individuals from Disadvantaged Backgrounds, National Institutes of Health, HHS)

Dated: August 5, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–20442 Filed 8–10–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–1989–DR; Docket ID FEMA–2011–0001]

Oklahoma; Amendment No. 4 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Oklahoma (FEMA–1989–DR), dated June 6, 2011, and related determinations.

DATES: *Effective Date:* August 3, 2011.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Oklahoma is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of June 6, 2011.

Craig and Nowata Counties for Public Assistance.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.)

W. Craig Fugate,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2011–20365 Filed 8–10–11; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4005–DR; Docket ID FEMA–2011–0001]

Tennessee; Amendment No. 1 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Tennessee (FEMA–4005–DR), dated July 20, 2011, and related determinations.

DATES: *Effective Date:* August 1, 2011.

FOR FURTHER INFORMATION CONTACT: Peggy Miller, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street, SW., Washington, DC 20472, (202) 646–3886.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the

State of Tennessee is hereby amended to include the following area among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of July 20, 2011.

Anderson County for Public Assistance.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.)

W. Craig Fugate,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2011–20366 Filed 8–10–11; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

Agency Information Collection Activities: Certificate of Origin

AGENCY: U.S. Customs and Border Protection, Department of Homeland Security.

ACTION: 30-Day Notice and request for comments; Extension of an existing collection of information.

SUMMARY: U.S. Customs and Border Protection (CBP) of the Department of Homeland Security will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act: Certificate of Origin (CBP Form 3229). This is a proposed extension of an information collection that was previously approved. CBP is proposing that this information collection be extended with a change to the burden hours. This document is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** (76 FR 19119) on April 6, 2011, allowing for a 60-day comment period. One comment was received. This notice allows for an additional 30 days for public comments. This process is conducted in accordance with 5 CFR 1320.10.

DATES: Written comments should be received on or before September 12, 2011.

ADDRESSES: Interested persons are invited to submit written comments on this proposed information collection to the Office of Information and Regulatory Affairs, Office of Management and Budget. Comments should be addressed to the OMB Desk Officer for Customs and Border Protection, Department of Homeland Security, and sent via electronic mail to *oira_submission@omb.eop.gov* or faxed to (202) 395–5806.

FOR FURTHER INFORMATION CONTACT: Requests for additional information should be directed to Tracey Denning, U.S. Customs and Border Protection, Regulations and Rulings, Office of International Trade, 799 9th Street, NW., 5th Floor, Washington, DC 20229–1177, at 202–325–0265.

SUPPLEMENTARY INFORMATION: CBP invites the general public and other Federal agencies to comment on proposed and/or continuing information collections pursuant to the Paperwork Reduction Act of 1995 (Pub. L. 104–13; 44 U.S.C. 3505(c)(2)). The comments should address: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimates of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden including the use of automated collection techniques or the use of other forms of information technology; and (e) the annual costs burden to respondents or record keepers from the collection of information (a total capital/startup costs and operations and maintenance costs). The comments that are submitted will be summarized and included in the CBP request for Office of Management and Budget (OMB) approval. All comments will become a matter of public record. In this document CBP is soliciting comments concerning the following information collection:

Title: Certificate of Origin.

OMB Number: 1651–0016.

Form Number: CBP Form 3229.

Abstract: CBP Form 3229, Certificate of Origin, is used by shippers to declare that goods being imported into the United States are produced or manufactured in a U.S. insular possession from materials grown, produced or manufactured in such possession, and to list the foreign materials included in the goods, including their description and value. CBP Form 3229 is used as documentation for goods entitled to enter the U.S. free of duty. This form is authorized by General Note 3(a)(iv) of the Harmonized Tariff Schedule of the Untied States (19 U.S.C. 1202) and is provided for by 19 CFR 7.3 CBP Form 3229 is accessible at: *http://forms.cbp.gov/pdf/CBP_Form_3229.pdf.*

Current Actions: CBP proposes to extend the expiration date of this information collection with a change to the burden hours based on revised estimates by CBP of the number of forms filed annually. There is no change to the information being collected or to CBP Form 3229.

Type of Review: Extension (with change).

Affected Public: Businesses.

Estimated Number of Respondents: 113.

Estimated Number of Responses per Respondent: 20.

Estimated Number of Total Annual Responses: 2,260.

Estimated Time per Response: 22 minutes.

Estimated Total Annual Burden Hours: 814.

Dated: August 8, 2011.

Tracey Denning,

Agency Clearance Officer, U.S. Customs and Border Protection.

[FR Doc. 2011–20449 Filed 8–10–11; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOMELAND SECURITY

CUSTOMS AND BORDER PROTECTION

Notice of Issuance of Final Determination Concerning Certain Digital Projectors

AGENCY: U.S. Customs and Border Protection, Department of Homeland Security.

ACTION: Notice of final determination.

SUMMARY: This document provides notice that U.S. Customs and Border Protection (''CBP'') has issued a final determination concerning the country of origin of certain digital projectors. Based upon the facts presented, CBP has concluded that the assembly and programming operations performed in Taiwan substantially transform the non-TAA country components of the projectors. Therefore, the country of

origin of the projectors is Taiwan for purposes of U.S. government procurement.

DATES: The final determination was issued on July 29, 2011. A copy of the final determination is attached. Any party-at-interest, as defined in 19 CFR 177.22(d), may seek judicial review of this final determination on or before September 12, 2011.

FOR FURTHER INFORMATION CONTACT: Heather K. Pinnock, Valuation and Special Programs Branch: (202) 325–0034.

SUPPLEMENTARY INFORMATION: Notice is hereby given that on July 29, 2011, pursuant to subpart B of part 177, U.S. Customs and Border Protection Regulations (19 CFR part 177, subpart B), CBP issued a final determination concerning the country of origin of digital projectors which may be offered to the U.S. Government under an undesignated government procurement contract. This final determination, HQ H146735, was issued under procedures set forth at 19 CFR part 177, subpart B, which implements Title III of the Trade Agreements Act of 1979, as amended (19 U.S.C. 2511–18). In the final determination, CBP concluded that, based upon the facts presented, the assembly and programming operations performed in Taiwan substantially transform the non-TAA country components of the projectors. Therefore, the country of origin of the projectors is Taiwan for purposes of U.S. government procurement.

Section 177.29, CBP Regulations (19 CFR 177.29), provides that a notice of final determination shall be published in the **Federal Register** within 60 days of the date the final determination is issued. Section 177.30, CBP Regulations (19 CFR 177.30), provides that any party-at-interest, as defined in 19 CFR 177.22(d), may seek judicial review of a final determination within 30 days of publication of such determination in the **Federal Register.**

Dated: July 29, 2011.

Sandra L. Bell,

Executive Director, Regulations and Rulings, Office of International Trade.

Attachment

HQ H146735

July 29, 2011

MAR–2 OT:RR:CTF:VS H146735 HkP

Category: Marking

Munford Page Hall, Esq.
William C. Sjoberg, Esq.
Adduci, Mastriani & Schaumberg LLP
1200 Seventeenth Street, NW
Washington, DC 20036.

RE: Final Determination; Substantial Transformation; Country of Origin of Certain Digital Projectors

Dear Mr. Hall and Mr. Sjoberg:

This is in response to your letter dated January 21, 2011, requesting a final determination on behalf of a foreign manufacturer, pursuant to subpart B of part 177 of the U.S. Customs and Border Protection (CBP) Regulations (19 C.F.R. Part 177). Under these regulations, which implement Title III of the Trade Agreements Act of 1979 (TAA), as amended (19 U.S.C. § 2511 *et seq.*), CBP issues country of origin advisory rulings and final determinations as to whether an article is or would be a product of a designated country or instrumentality for the purposes of granting waivers of certain ''Buy American'' restrictions in U.S. law or practice for products offered for sale to the U.S. Government.

This final determination concerns the country of origin of two models of digital projectors. We note that as the manufacturer of the digital projectors, the foreign manufacturer is a party-at-interest within the meaning of 19 CFR 177.22(d)(1) and is entitled to request this final determination.

Facts:

According to the submitted information, the subject merchandise is two models of digital projectors, Model A and Model B (collectively, the digital projector). The projector is a 9cm x 30cm x 20cm, 2.5kg, digital light processing (DLP) projector, designed to use a high-intensity discharge (HID) arc lamp as the light source to project images from computers and other video sources. It can produce an image size of up to 307 inches diagonally. The main differences between Model A and Model B are the resolution of the projected image and the throw ratio (basically the viewing distance from the screen).

The projector is composed of the following components:

Components of Taiwanese origin include:

(1) System firmware, which controls the functions of the keypad, remote controller, USB port, lamp brightness, volume, and on-screen display main menu, as well as image processing. The fully assembled projector is programmed in Taiwan with this firmware.

(2) Power control firmware, used to control the on/off function of the projector and to retrieve the input/output (I/O) setting of the projector in the latest turn-off from an electronically erasable programmable read only memory (EEPROM). The firmware detects the power signal and transmits the command to the low voltage power supply (LVPS) to output the required voltage for the system and the lamp. The firmware also controls the operation of the fans and detects their operating status. The fully assembled projector is programmed in Taiwan with this firmware.

(3) Extended Display Identification Data (EDID) firmware, a Video Electronics Standard Association (VESA) data format that contains basic information about the projector and its capabilities, including vendor information, maximum image size, color characteristics, factory pre-set timings, frequency range limits, and character strings for the model name and serial number. The information is stored in the display and uses the Display Data Channel (DDC) to communicate between the projector and a personal computer graphics adapter. The system uses this information for configuration purposes. The fully assembled projector is programmed in Taiwan with this firmware.

(4) Network firmware, which contains the network protocol, is used to receive instructions to control the projector from a remote user using a computer. The firmware may be updated in Taiwan during the assembly and testing processes.

Components of Chinese origin include:

(1) Bottom cover module, comprised of parts from Korea, China, and Taiwan.

(2) Elevator module, used to adjust the height of the projector, comprised of parts from China and Japan.

(3) Right cover module, comprised of parts from China.

(4) Input/Output (I/O) cover module, comprised of parts from China.

(5) Top cover module, comprised of parts from Japan, Taiwan, China, the U.S., and Korea.

(6) Cosmetic module, comprised of parts from China.

(7) Fan modules, comprised of the system (axial) fan module and the lamp blower module attached to the lamp housing, comprised of parts from China.

(8) Lamp driver (ballast) module, comprised of parts from China.

(9) Lamp driver firmware, used to control lamp ignition and to obtain the ballast waveform that controls the output current with respect to the angle of the color wheel. White light, generated by a high intensity discharge arc lamp, passes through the filter to generate different colors. The firmware is programmed into an IC on the lamp driver module (Chinese component no. 8) in China.

(10) Color wheel module, which includes the color wheel, photo sensor board with photo sensor, and bracket. It acts as a time-varying wavelength filter to allow certain wavelengths of light to pass through at the appropriate times so that the filtered light may be modulated by the light valve, DMD (digital micromirror device, *i.e.,* an optical semiconductor), to produce the projected image with full color. Module parts are from Japan, China, and Taiwan.

(11) Zoom ring module, comprised of parts from China.

(12) Lamp module, comprised of parts from China.

(13) Lamp cover module, comprised of parts from China.

(14) Semi-finished optical engine module, which includes a Taiwanese-origin DMD, a DMD board, an optical lens, a projection lens, and rod integrator. Module parts are from Taiwan and China.

(15) Main board module, which stores the system firmware (Taiwanese component no. 1) on a Taiwanese-origin DDP2431 processor, comprised of parts from China, the Czech Republic, Taiwan, Japan, Korea, and the U.S.

(16) Low voltage power supply (LVPS) module, comprised of parts from Taiwan, Japan, Korea, China, and the U.S.

(17) Local area network (LAN) module board, comprised of parts from the U.S. and

unnamed countries. It is programmed with Taiwanese-origin network firmware (Taiwanese component no. 4) in China.

(18) Miscellaneous items: screws, EMI gaskets, tape (Mylar and 3M), 16-pin wiring, brackets, main board spacers, insulating rubber, Mylar film, and elevator feet.

Modules 1–8 and 10–17 are assembled in China and shipped to Taiwan. The miscellaneous Chinese components described at no. 18 above are also shipped to Taiwan to be assembled with the 16 Chinese modules.

In Taiwan, the imported modules and components are inspected and then assembled into a complete digital projector using the Chinese screws, EMI gaskets, tape (Mylar and 3M), 16-pin wiring, brackets, main board spacers, insulating rubber, Mylar film, and an elevator foot. The projector is then programmed with the power control firmware and system firmware developed in Taiwan, and then subjected to various tests. During the testing stage, the projector is also loaded with Taiwanese-origin EDID firmware, which programs the identification of the projector into the EEPROM on the main board.

ISSUE:

What is the country of origin of the projector for purposes of U.S. government procurement?

LAW AND ANALYSIS:

Pursuant to Subpart B of Part 177, 19 C.F.R. § 177.21 et seq., which implements Title III of the Trade Agreements Act of 1979, as amended (19 U.S.C. § 2511 et seq.), CBP issues country of origin advisory rulings and final determinations as to whether an article is or would be a product of a designated country or instrumentality for the purposes of granting waivers of certain ''Buy American'' restrictions in U.S. law or practice for products offered for sale to the U.S. Government.

Under the rule of origin set forth under 19 U.S.C. § 2518(4)(B):

An article is a product of a country or instrumentality only if (i) it is wholly the growth, product, or manufacture of that country or instrumentality, or (ii) in the case of an article which consists in whole or in part of materials from another country or instrumentality, it has been substantially transformed into a new and different article of commerce with a name, character, or use distinct from that of the article or articles from which it was so transformed.

See also 19 C.F.R. § 177.22(a).

In determining whether the combining of parts or materials constitutes a substantial transformation, the determinative issue is the extent of operations performed and whether the parts lose their identity and become an integral part of the new article. *Belcrest Linens v. United States,* 573 F. Supp. 1149 (Ct. Int'l Trade 1983), *aff'd,* 741 F.2d 1368 (Fed. Cir. 1984). Assembly operations that are minimal or simple, as opposed to complex or meaningful, will generally not result in a substantial transformation.

In *Data General* v. *United States,* 4 Ct. Int'l Trade 182 (1982), the court determined that for purposes of determining eligibility under item 807.00, Tariff Schedules of the United States (predecessor to subheading 9802.00.80, Harmonized Tariff Schedule of the United States), the programming of a foreign PROM (Programmable Read-Only Memory chip) in the United States substantially transformed the PROM into a U.S. article. In programming the imported PROMs, the U.S. engineers systematically caused various distinct electronic interconnections to be formed within each integrated circuit. The programming bestowed upon each circuit its electronic function, that is, its ''memory'' which could be retrieved. A distinct physical change was effected in the PROM by the opening or closing of the fuses, depending on the method of programming. This physical alteration, not visible to the naked eye, could be discerned by electronic testing of the PROM. The court noted that the programs were designed by a U.S. project engineer with many years of experience in ''designing and building hardware.'' While replicating the program pattern from a ''master'' PROM may be a quick one-step process, the development of the pattern and the production of the ''master'' PROM required much time and expertise. The court noted that it was undisputed that programming altered the character of a PROM. The essence of the article, its interconnections or stored memory, was established by programming. The court concluded that altering the non-functioning circuitry comprising a PROM through technological expertise in order to produce a functioning read only memory device, possessing a desired distinctive circuit pattern, was no less a ''substantial transformation'' than the manual interconnection of transistors, resistors and diodes upon a circuit board creating a similar pattern.

You argue that Taiwan is the country of origin of the projector because it is the country in which the following actions occur: design and development of the projector, including the main board; addition of the majority of the value (materials and labor); fabrication of many parts, including the data processors (the DMD and DDP2431) that are claimed to be the major functional parts of the projector; development of four of the five firmware files used to operate the projector; programming of the main board with system firmware and programming of the control panel with power control firmware; assembly of the Chinese modules with disparate parts to make a functional projector; and, testing and adjustment of the projector. You point out that 60 percent of the total cost of materials (including accessories and packing material) comes from the United States and TAA designated countries, and that the processing in Taiwan will require 180 steps, including assembly, programming, testing, and packing.

Further, you claim that the Chinese modules are substantially transformed in Taiwan when they are assembled into a projector. As a result of the color wheel module being assembled with the semi-finished optical engine module in Taiwan, the HID arc lamp can be used as a light source and the DMD can be used as a light valve to produce color images. When the lamp ballast is connected to the LVPS, the ballast gains a power source, and when connected to the main board, the lamp can be controlled. Connecting the Chinese main board module to the semi-finished optical engine module, the DMD board, fan modules, and color wheel module allows all the boards attached to the main module to be controlled. The LVPS powers the main board so that the modules attached to it can operate. Finally, assembling the top cover module with the main board module allows the projector to be controlled through the keypad.

You state that factors such as the resources expended on design and development, extent and nature of post-assembly inspection and testing procedure, and worker skill required during the manufacturing process have been considered in determining whether a substantial transformation occurred. In support of your position you cite Headquarters Ruling Letters (HQ) H100055 (May 8, 2010), H034843 (May 5, 2009), and H015324 (April 23, 2008), 559534 (June 4, 1996), among others.

HQ H100055 concerned a motorized lift unit, designed, developed and engineered in Sweden, for an overhead patient lift system. The PCBA was assembled and programmed prior to its importation in Sweden but it was designed in Sweden and its software program was written in Sweden. The unit was then assembled in Sweden, which included the manufacture of the electrical motor. CBP found that the manufacturing and testing operations in Sweden were sufficiently complex and meaningful to transform the individual components into the lift unit, thereby making Sweden the country of origin of the unit. HQ H034843 concerned a USB flash drive partially manufactured in China and in Israel or the United States. CBP concluded that there was a substantial transformation either in Israel or in the United States, depending on the location where the final three manufacturing operations took place. HQ H015324 involved stereoscopic displays assembled in the U.S. from non-U.S. parts. U.S. assembly resulted in a substantial transformation of imported LCD monitors and a beamsplitter mirror.

In this case, the bottom cover module, elevator module, right cover module, I/O cover module, cosmetic module, two fan modules, lamp driver module programmed in China with Chinese firmware, zoom ring module, lamp module, lamp cover module, semi-finished optical engine module, color wheel module, main board module, top cover module, LAN module programmed in China with Taiwanese-origin firmware, and the LVPS module, from China are assembled together in Taiwan with other Chinese components to form a complete projector. After assembly, the projector is programmed in Taiwan with three types of firmware developed in Taiwan. The first, power control firmware, is used to control on/off functions and to retrieve the input/output setting from the last time the projector was turned off. The second, system firmware, controls the functions of the keypad, remote control, USB port, lamp brightness, volume, on-screen display menu, and image processing. The third, EDID firmware, contains basic information about the projector, such as maximum image size, color characteristics, factory pre-set timings, and frequency range limits. We find that the assembly and programming operations performed in Taiwan are sufficiently complex and meaningful so as to create a new article with a new character, name and use. *See, for e.g.,* HQ H034843 and H100055. Moreover, we note that some of the Chinese modules were made using Taiwanese parts. Through the operations undertaken in Taiwan, the individual parts lose their identities and become integral to the new and different article, i.e., the projector. *See Belcrest Linens.* Accordingly, we find that the country of origin of the projector is Taiwan.

HOLDING:

Based on the facts in this case, we find that the assembly and programming operations performed in Taiwan substantially transform the non-TAA country components of the projector. Therefore, the country of origin of the Model A and Model B projectors is Taiwan for purposes of U.S. government procurement.

Notice of this final determination will be given in the **Federal Register**, as required by 19 C.F.R. § 177.29. Any party-at-interest other than the party which requested this final determination may request, pursuant to 19 C.F.R. § 177.31, that CBP reexamine the matter anew and issue a new final determination. Pursuant to 19 C.F.R. § 177.30, any party-at-interest may, within 30 days of publication of the **Federal Register** Notice referenced above, seek judicial review of this final determination before the Court of International Trade.

Sincerely,

Sandra L. Bell, *Executive Director, Regulations and Rulings Office of International Trade.*

[FR Doc. 2011–20452 Filed 8–10–11; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

Notice of Intent To Prepare an Environmental Impact Statement for the Proposed Samish Indian Nation Fee-to-Trust Acquisition and Casino Project, Skagit County, WA

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice.

SUMMARY: The Bureau of Indian Affairs (BIA) as lead agency is gathering information necessary for preparing an Environmental Impact Statement (EIS) in connection with the Samish Indian Nation's (Tribe's) application for a proposed 11.41-acre fee-to-trust transfer and casino project to be located in Anacortes, Washington. The purpose of the proposed action is to improve the economic status of the tribal government so it can better provide housing, health care, education, cultural programs, and other services to its members. This notice also announces a public scoping meeting to identify potential issues and content for inclusion in the EIS.

DATES: Written comments on the scope of the EIS will be accepted until September 16, 2011. The public scoping meeting will be held on September 14, 2011, from 6 p.m. to 9 p.m. PDT, or until the last comment is heard.

ADDRESSES: You may mail or hand carry written comments to Mr. Stanley Speaks, Northwest Regional Director, Bureau of Indian Affairs, Northwest Region, 911 NE 11th Avenue, Portland, Oregon 97232. Please include your name, return caption, address and ''DEIS Scoping Comments, Samish Indian Nation Casino Project'' on the first page of your written comments. The public scoping meeting will be held at Fidalgo Bay Resort Community Center, 4701 Fidalgo Bay Road, Anacortes, WA 98221.

FOR FURTHER INFORMATION CONTACT: Dr. B.J. Howerton, Environmental Protection Specialist, BIA Northwest Region, (503) 231–6749.

SUPPLEMENTARY INFORMATION: The proposed action would transfer approximately 11.41 acres of land from fee to trust status. After the transfer, the Tribe would develop a casino, parking, and other supporting facilities. The property is located within the incorporated boundaries of the City of Anacortes, Washington, southeast of the intersection of Thompson Road and State Route 20. Areas of environmental concern identified for analysis in the EIS include land resources, water resources, air quality, noise, biological resources, cultural resources, resource use patterns, traffic and transportation, public health/environmental hazards, public services and utilities, socioeconomics, environmental justice, and visual resources/aesthetics. Alternatives identified for analysis include the proposed action, a no-action alternative, a reduced-intensity development alternative, a non-gaming alternative, and an alternate site location alternative. The range of issues and alternatives is open to revision based on comments received in response to this notice. Additional information, including a map of the project site, is available by contacting the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice. Other related approvals may be required to implement the project, including approval of the Tribe's fee-to-trust application, determination of the site's eligibility for gaming, compliance with the Clean Water Act, and local service agreements. To the extent applicable, the EIS will identify and evaluate issues related to these approvals.

Public Comment Availability

Comments, including names and addresses of respondents, will be available for public review at the address shown in the **ADDRESSES** section, during regular business hours, 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask in your comment that your personal identifying information be withheld from public review, we cannot guarantee that this will occur.

Authority

This notice is published in accordance with sections 1503.1 of the Council on Environmental Quality Regulations (40 CFR parts 1500 through 1508) and section 46.305 of the Department of the Interior Regulations (43 CFR part 46), implementing the procedural requirements of NEPA, as amended (42 U.S.C. 4321 *et seq.*), and is in the exercise of authority delegated to the Assistant Secretary—Indian Affairs, by part 209 of the Departmental Manual.

Dated: July 29, 2011.

Larry Echo Hawk,

Assistant Secretary—Indian Affairs.

[FR Doc. 2011–20476 Filed 8–10–11; 8:45 am]

BILLING CODE 4310–W7–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLCA 942000 L57000000 BX0000]

Filing of Plats of Survey: California

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The plats of survey and supplemental plats of lands described below are scheduled to be officially filed in the Bureau of Land Management California State Office, Sacramento, California, thirty (30) calendar days from the date of this publication.

ADDRESSES: A copy of the plats may be obtained from the California State Office, Bureau of Land Management, 2800 Cottage Way, Sacramento, California 95825, upon required payment.

Protest: A person or party who wishes to protest a survey must file a notice that they wish to protest with the California State Director, Bureau of Land Management, 2800 Cottage Way, Sacramento, California 95825.

FOR FURTHER INFORMATION CONTACT: Chief, Branch of Geographic Services, Bureau of Land Management, California State Office, 2800 Cottage Way, Room W–1623, Sacramento, California 95825, (916) 978–4310.

SUPPLEMENTARY INFORMATION: These surveys and supplemental plats were executed to meet the administrative needs of various federal agencies; the Bureau of Land Management, Bureau of Indian Affairs or General Services Administration. The lands surveyed are:

Mount Diablo Meridian, California

T. 26 S., R. 33 E., Dependent resurvey and metes-and-bounds survey, accepted May 10, 2011.
T. 23 S., R. 16 E., Dependent resurvey and subdivision of section 20, accepted June 29, 2011.

San Bernardino Meridian, California

T. 9 S., R. 2 W., Supplemental plat of the NW ¼ of the SW ¼ section 34, accepted April 5, 2011.
T. 2 N., R. 17 W., Metes-and-bounds survey, accepted May 9, 2011.
T. 8 S., R. 2 E., Dependent resurvey and subdivision of sections 11 and 12, accepted May 10, 2011.
T. 8 S., R. 3 E., Dependent resurvey and subdivision of sections 7 and 8, accepted May 10, 2011.
T. 9 N., R. 32 W., Supplemental plat, accepted May 16, 2011.
T. 4 S., R. 4 E., Supplemental plat of the NE ¼ SE ¼ of section 26, accepted June 3, 2011.
T. 5 N., R. 28 W., Dependent resurvey, accepted July 22, 2011.

Authority: 43 U.S.C., Chapter 3.

Dated: May 7, 2010.

Lance J. Bishop,

Chief Cadastral Surveyor, California.

[FR Doc. 2011–20457 Filed 8–10–11; 8:45 am]

BILLING CODE 4310–40–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLCAN01000.L10200000.XZ0000]

Notice of Public Meeting: Northwest California Resource Advisory Council

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of Public Meeting.

SUMMARY: In accordance with the Federal Land Policy and Management Act of 1976 (FLPMA), and the Federal Advisory Committee Act of 1972 (FACA), the U. S. Department of the Interior, Bureau of Land Management (BLM) Northwest California Resource Advisory Council will meet as indicated below.

DATES: The meeting will be held Wednesday and Thursday, Sept. 7 and 8, 2011, at the BLM Arcata Field Office, 1695 Heindon Rd., Arcata, California. On Sept. 7, the RAC will convene at 10 a.m. and depart for a field tour to the Lost Coast Headlands project and the South Spit Management Area. Members of the public are welcome. They must provide their own transportation, food and beverages. On Sept. 8, the council will convene at 8 a.m. in the Conference Room of the BLM Arcata Field Office. The meeting is open to the public. Time for public comment has been reserved at 11 a.m.

FOR FURTHER INFORMATION CONTACT: Nancy Haug, BLM Northern California District manager, (530) 224–2160; or BLM Public Affairs Officer Joseph J. Fontana, (530) 252–5332.

SUPPLEMENTARY INFORMATION: The 12-member council advises the Secretary of the Interior, through the BLM, on a variety of planning and management issues associated with public land management in Northwest California. At this meeting agenda topics include management of the King Range National Conservation Area, status of the Walker Ridge Wind Energy proposal, management of the Sacramento River Bend Area of Critical Environmental Concern and environmental education programs. All meetings are open to the public. Members of the public may present written comments to the council. Each formal council meeting will have time allocated for public comments. Depending on the number of persons wishing to speak, and the time available, the time for individual comments may be limited. Members of the public are welcome on field tours, but they must provide their own transportation and lunch. Individuals who plan to attend and need special assistance, such as sign language interpretation and other reasonable accommodations, should contact the BLM as provided above.

Dated: August 3, 2011.

Joseph J. Fontana,

Public Affairs Officer.

[FR Doc. 2011–20462 Filed 8–10–11; 8:45 am]

BILLING CODE 4310–40–P

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

Notice of Availability of the Final Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the Nimbus Hatchery Fish Passage Project, Lower American River, California

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice of availability.

SUMMARY: The Bureau of Reclamation (Reclamation), the lead Federal agency, and the California Department of Fish and Game (CDFG), the lead State agency, have prepared a joint Final EIS/EIR for the proposed Nimbus Fish Hatchery Weir Replacement Project (Project). The purpose of the Project is to create and maintain a reliable system of collecting adult fish for use in the Nimbus Fish Hatchery (Hatchery).

DATES: Reclamation will not make a decision on the proposed action until at least 30 days after release of the Final EIS/EIR. After the 30-day waiting period, Reclamation will complete a Record of Decision (ROD). The ROD will state the action that will be implemented and discuss all the factors that led to the decision.

The CDFG will advance its recommendations to the California Fish and Game Commission (Commission) for consideration. The Commission will hold additional hearings on the recommendations and a Notice of Determination will be filed after the hearings. This action will trigger a 30-day review period under California Environmental Quality Act.

ADDRESSES: Copies of the Final EIS/EIR may be requested from Ms. Janet Sierzputowski at 916–978–5112, TTY 916–978–5608, or e-mail *jsierzputowski@usbr.gov.*

The Final EIS/EIR is also accessible from the following Web site: *http://www.usbr.gov/mp/nepa/nepa_projdetails.cfm?Project_ID=5216* or *http://www.usbr.gov/mp/ccao/hatchery/index.html.*

See the **SUPPLEMENTARY INFORMATION** section for locations where copies of the Final EIS/EIR are available for public review.

FOR FURTHER INFORMATION CONTACT: Mr. David Robinson, Central California Area Office (CCAO), Bureau of Reclamation, at the CCAO general telephone number 916–988–1707, *e-mail: HatchPass@usbr.gov.*

SUPPLEMENTARY INFORMATION: The Nimbus Hatchery is located along the lower American River approximately ¼ mile downstream from Nimbus Dam in Rancho Cordova, CA. The Hatchery is a mitigation facility that was constructed by Reclamation in 1955 to compensate for the loss of spawning habitat for Chinook salmon and steelhead trout inundated by the construction of Nimbus Dam. The Hatchery annually produces about 4 million fall-run Chinook salmon smolts and 430,000 winter-run American River steelhead yearlings. A fish weir is currently used to prevent adult salmon from continuing upstream and allows them to locate and enter the fish ladder and hatchery.

The Project is needed because the existing weir is aging, susceptible to periodic significant damage from high flows, and its operation requires annual flow reductions to perform maintenance which affect protected steelhead populations in the river. Annual short-term flow reductions when steelheads are rearing in the lower American River are required to install the weir. Flow reductions of longer duration are periodically required to repair significant flood damage to the existing structure and scouring around its foundation. This scouring is harmful because it destabilizes the weir and creates large holes that upstream migrant fish can pass through and therefore fail to enter into the hatchery ladder.

The primary objective of the Project is to maintain a fully functional system of collecting adult fish sufficient to meet mitigation goals. Secondary objectives are to minimize operation and maintenance costs, avoid reducing river flows, and improve safety. Reclamation has evaluated a broad set of potential solutions in a series of planning evaluations beginning in the mid-1990s. Two approaches to solving the problems that were advanced through the planning process are: (1) Constructing a new fish diversion weir with a concrete foundation and air bladder control gates and pickets; and (2) extending the fish ladder upstream to Nimbus Dam and removing the existing fish diversion weir. The EIS/EIR evaluates each of these alternative approaches and a no action alternative.

CDFG has continuously operated and maintained the Hatchery under contract with Reclamation since it was originally constructed in 1955. CDFG operates and maintains all salmon and steelhead hatcheries within the State of California and is responsible for the management of statewide fisheries resources. As manager of the State fisheries resources, CDFG is also responsible for recommending and implementing fishing regulations. One alternative under consideration would result in changes to the fishing opportunities immediately downstream from Nimbus Dam pursuant to CDFG Regulation Section 2.35, ''Taking Fish near Dams, Screens, and Egg-taking Stations,'' and likely would result in significant impacts to the Chinook salmon population. CDFG is also considering modification to the seasonal fishing regulations between the Hatchery and Nimbus Dam as part of the evaluation of this alternative.

A Notice of Availability of the Draft EIS/EIR and a schedule for public meetings was published in the **Federal Register** on October 01, 2010 (75 FR 60804). The formal comment period on the Draft EIS/EIR ended on November 30, 2010. The Final EIS/EIR contains responses to all comments received and reflects comments and any additional information received during the review period.

Copies of the Final EIS/EIR are available for public review at the following locations:

- Bureau of Reclamation, Denver Office Library, Building 67, Room 167, Denver Federal Center, 6th and Kipling, Denver, CO 80225.
- Natural Resources Library, Department of the Interior, 1849 C Street, NW., Main Interior Building, Washington, DC 20240–0001.
- Bureau of Reclamation, Mid-Pacific Region, Regional Library, 2800 Cottage Way, Sacramento, CA 95825.
- Central California Area Office, Bureau of Reclamation, 7794 Folsom Dam Road, Folsom, CA 95630.
- Nimbus Fish Hatchery, 2001 Nimbus Road, Gold River, CA 95670.

Dated: July 25, 2011.

Pablo R. Arroyave,

Deputy Regional Director, Mid-Pacific Region.

[FR Doc. 2011–20393 Filed 8–10–11; 8:45 am]

BILLING CODE 4310–MN–P

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

Rural Water Supply Program Approved Appraisal Reports; Availability

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice of availability.

SUMMARY: Reclamation provides assistance for appraisal investigations and feasibility studies for rural water supply projects intended to serve a community or group of communities with domestic, industrial, and municipal water. This assistance helps rural communities assess their potable water needs and identify options to address those needs.

Three appraisal reports were approved in Fiscal Year 2010 and two were approved in Fiscal Year 2011. The initial appraisal investigations were submitted by the participants for review to assess technical adequacy and completeness. Once reviewed, Reclamation prepared these reports to document the findings and conclusions of the appraisal investigations that identified the water supply problems, needs, and opportunities in the planning study areas. The approval of an appraisal report indicates that there is a viable alternative that warrants a more detailed investigation through a feasibility study.

SUPPLEMENTARY INFORMATION: The approved appraisal reports can be downloaded from our Web site: *http://www.usbr.gov/ruralwater.*

FOR FURTHER INFORMATION CONTACT: Mr. Joseph Wilson by telephone at (303) 445–2856, or by e-mail at *jwilson@usbr.gov.* Copies are also available for public review at the following locations:

- Dry-Redwater Rural Water System Appraisal Report, Bureau of Reclamation, Montana Area Office, 2900 Fourth Avenue North, Billings, MT 59101, (406) 247–7300
- Douglas County Rural Water Project Appraisal Report, Bureau of Reclamation, Eastern Colorado Area Office, 11056 W. County Rd 18E, Loveland, CO 80537–9711, (970) 667–4410
- Lower Niobrara Natural Resource District Appraisal Report, Bureau of Reclamation, Nebraska Kansas Area Office, 203 West 2nd Street, Grand Island, NE 68801–5907, (308) 389–5301
- Musselshell-Judith Rural Water System Appraisal Report, Bureau of Reclamation, Montana Area Office, 2900 Fourth Avenue North, Billings, MT 59101, (406) 247–7300
- Southern Black Hills Regional Water System Appraisal Report, Bureau of Reclamation, Dakotas Area Office, 304 E. Broadway Avenue, Bismarck, ND 58501, (701) 250–4242 x3101

Authority

Reclamation Rural Water Supply Act of December 22, 2006 (Pub. L. 109–451, Title I, 120 Stat. 3346, 43 U.S.C. 2401, *et seq.*) authorizes Reclamation to establish a program to work with rural communities, including Indian tribes, in the 17 Western States to assess rural water supply needs and identify options to address those needs through appraisal investigations and feasibility studies.

Background

The Douglas County Rural Water Project Appraisal Report addresses the County's extremely low recharge into and high withdrawal amounts from the Denver Basin aquifers and proposes to resolve this issue by replacing current groundwater supplies with an alternative source of water. The proposed alternative includes water treatment, raw and finished water transmission, finished water storage, and aquifer storage and recovery for delivery of surface water from existing diversions and water impoundments on the South Platte River to this large rural region of central Colorado.

The Dry-Redwater Rural Water System project would serve a population of about 15,000 people in the project area, including the towns of Circle, Richey, Jordan, and Fairview; the unincorporated town of Lambert; the water districts of Highland Park, Forrest Park, Spring Grove, and Whispering Tree; and rural users in the service area. It examines opportunities to provide communities, unincorporated areas, and rural areas in east-central Montana with a present and future source of high quality water from North Rock Creek in the Big Dry Arm of Fort Peck Reservoir.

The Musselshell-Judith Rural Water System Appraisal Investigation was conducted by the Central Montana Regional Water Authority to assess the viability of developing a rural water system to serve about 4,500 people in 15 incorporated and unincorporated towns in central Montana. The proposed alternative would supply water to the system from a field of groundwater wells in the Utica, Montana area. Water pumped from the Madison Aquifer, a deep underground aquifer, would be distributed from the well field by a branch type system of pipelines, booster pump stations, and storage tanks.

The Lower Niobrara project area is located in Knox County in northeast Nebraska. There is a growing need for an improved water source because of rising nitrate levels in some areas. The proposed study area comprises approximately the central one-third of Knox County, which includes the West Knox Rural Water System (RWS), the Santee Sioux Reservation, and the towns of Creighton, Niobrara, and Center. The preferred alternative for Lower Niobrara consists of expanding the West Knox RWS Well Field to supply Creighton, Niobrara, Center, and the Santee Sioux Reservation.

The Southern Black Hills Water System (SBHWS) project is designed to provide a regional water supply and water delivery system for rural users, special use needs, and community needs for southern Pennington County, all of Custer County, and all of Fall River County, in southwestern South Dakota. The SBHWS appraisal investigation evaluated a number of alternatives ranging from purchasing water from an existing entity, developing new infrastructure, and some non-structural alternatives which include water use polices (e.g., prohibit rural residential growth) and water conservation (e.g., leak detection surveys).

Dated: *July 11, 2011.*

Roseann Gonzales,

Director, Policy and Administration.

[FR Doc. 2011–20392 Filed 8–10–11; 8:45 am]

BILLING CODE 4310–MN–P

DEPARTMENT OF LABOR

Employee Benefits Security Administration

Exemptions From Certain Prohibited Transaction Restrictions

AGENCY: Employee Benefits Security Administration, Labor.

ACTION: Grant of Individual Exemptions.

SUMMARY: This document contains exemptions issued by the Department of Labor (the Department) from certain of the prohibited transaction restrictions of the Employee Retirement Income Security Act of 1974 (ERISA or the Act) and/or the Internal Revenue Code of 1986 (the Code). This notice includes the following: D–11468 and D–11469, The Krispy Kreme Doughnut Corporation Retirement Savings Plan (the Savings Plan) and the Krispy Kreme Profit-Sharing Stock Ownership Plan the KSOP (together, the Plans), 2011–10; D–11634, The United Brotherhood of Carpenters Pension Fund (the Plan), 2011–11; and L–11651 and L–11652, Verizon Communications, Inc. (Verizon and Cellco Partnership, doing business as Verizon Wireless (Verizon Wireless; collectively the Applicants), 2011–12 *et al.*

SUPPLEMENTARY INFORMATION: A notice was published in the **Federal Register** of the pendency before the Department of a proposal to grant such exemption. The notice set forth a summary of facts and representations contained in the application for exemption and referred interested persons to the application for a complete statement of the facts and representations. The application has been available for public inspection at the Department in Washington, DC. The notice also invited interested persons to submit comments on the requested exemption to the Department. In addition the notice stated that any interested person might submit a written request that a public hearing be held (where appropriate). The applicant has represented that it has complied with the requirements of the notification to interested persons. No requests for a hearing were received by the Department. Public comments were received by the Department as described in the granted exemption.

The notice of proposed exemption was issued and the exemption is being granted solely by the Department because, effective December 31, 1978, section 102 of Reorganization Plan No. 4 of 1978, 5 U.S.C. App. 1 (1996), transferred the authority of the Secretary of the Treasury to issue exemptions of the type proposed to the Secretary of Labor.

Statutory Findings

In accordance with section 408(a) of the Act and/or section 4975(c)(2) of the Code and the procedures set forth in 29 CFR Part 2570, Subpart B (55 FR 32836, 32847, August 10, 1990) and based upon the entire record, the Department makes the following findings:

(a) The exemption is administratively feasible;

(b) The exemption is in the interests of the plan and its participants and beneficiaries; and

(c) The exemption is protective of the rights of the participants and beneficiaries of the plan.

The Krispy Kreme Doughnut Corporation Retirement Savings Plan (the Savings Plan) and the Krispy Kreme Profit-Sharing Stock Ownership Plan the KSOP; together, the Plans) [Prohibited Transaction Exemption 2011–10; Located in Winston-Salem, North Carolina [Exemption Application Nos. D–11468 and D–11469, respectively]

Exemption

The restrictions of section 406(a)(1)(A),(D),(E), section 406(a)(2), section 406(b)(2) and section 407(a) of the Act and the sanctions resulting from the application of section 4975 of the Code, by reason of section 4975(c)(1)(A) and (D) of the Code, shall not apply, effective January 16, 2007, to (1) the release by the Plans of their claims against Krispy Kreme Doughnut Corporation (KKDC), the sponsor of the Plans, Michael Phalen and Price waterhouseCoopers LLP (PwC), parties in interest with respect to the Plan, in exchange for cash, shares of common stock (the Common Stock) and warrants (the Warrants) issued by Krispy Kreme

Doughnuts, Inc. (KKDI), the parent of KKDC and also a party in interest, in settlement of certain litigation (the Securities Litigation) between the Plans and KKDC, Mr. Phalen and PwC; and (2) the holding of the Warrants by the Plans.

This exemption is subject to the following conditions:

(a) The receipt and holding of cash, the Common Stock and the Warrants occurred in connection with a genuine controversy in which the Plans were parties.

(b) An independent fiduciary was retained on behalf of the Plans to determine whether or not the Plans should have joined in the Securities Litigation and accept cash, the Common Stock and the Warrants pursuant to a settlement agreement (the Settlement Agreement). Such independent fiduciary—

(1) Had no relationship to, or interest in, any of the parties involved in the Securities Litigation that might affect the exercise of such person's judgment as a fiduciary;

(2) Acknowledged, in writing, that it was a fiduciary for the Plans with respect to the settlement of the Securities Litigation; and

(3) Determined that an all cash settlement was either not feasible or was less beneficial to the participants and beneficiaries of the Plans than accepting all or part of the settlement in non-cash assets.

(4) Thoroughly reviewed and determined whether it would be in the best interests of the Plans and their participants and beneficiaries to engage in the covered transactions.

(5) Determined whether the decision by the Plans' fiduciaries to cause the Plans not to opt out of the Securities Litigation was more beneficial to the Plans than having the Plans file a separate lawsuit against KKDC.

(c) The terms of the Settlement Agreement, including the scope of the release of claims, the amount of cash and the value of any non-cash assets received by the Plans, and the amount of any attorney's fee award or any other sums to be paid from the recovery were reasonable in light of the Plans' likelihood of receiving full recovery, the risks and costs of litigation, and the value of claims foregone.

(d) The terms and conditions of the transactions were no less favorable to the Plans than comparable arm's length terms and conditions that would have been agreed to by unrelated parties under similar circumstances.

(e) The transactions were not part of an agreement, arrangement, or understanding designed to benefit a party in interest.

(f) All terms of the Settlement Agreement were specifically described in a written document approved by the United States District Court for the Middle District of North Carolina.

(g) Non-cash assets, which included the Common Stock and Warrants received by the Plans from KKDC under the Settlement Agreement, were specifically described in the Settlement Agreement and valued as determined in accordance with a court-approved objective methodology;

(h) The Plans did not pay any fees or commissions in connection with the receipt or holding of the Common Stock and the Warrants.

(i) KKDC maintains, or causes to be maintained, for a period of six years such records as are necessary to enable the persons described in paragraph (j)(1) below to determine whether the conditions of this exemption have been met, except that—

(1) If the records necessary to enable the persons described in paragraph (j)(1) to determine whether the conditions of this exemption have been met are lost, or destroyed, due to circumstances beyond the control of KKDC, then no prohibited transaction will be considered to have occurred solely on the basis of the unavailability of those records; and

(2) No party in interest with respect to the Plans other than KKDC shall be subject to the civil penalty that may be assessed under section 502(i) of the Act or to the taxes imposed by section 4975(a) and (b) of the Code if such records are not maintained or are not available for examination as required by paragraph (i).

(j)(1) Except as provided in this paragraph (j) and notwithstanding any provision of section 504(a)(2) and (b) of the Act, the records referred to in paragraph (i) above are unconditionally available at their customary locations for examination during normal business hours by:

(A) Any duly authorized employee, agent or representative of the Department or the Internal Revenue Service, or the Securities and Exchange Commission (SEC);

(B) Any fiduciary of the Plans or any duly authorized representative of such participant or beneficiary;

(C) Any participant or beneficiary of the Plans or duly authorized representative of such participant or beneficiary;

(D) Any employer whose employees are covered by the Plans; or

(E) Any employee organization whose members are covered by such Plans.

(2) None of the persons described in paragraph (j)(1)(B) through (E) shall be authorized to examine trade secrets of KKDC or commercial or financial information which is privileged or confidential.

(3) Should KKDC refuse to disclose information on the basis that such information is exempt from disclosure, KKDC shall, by the close of the thirtieth (30th) day following the request, provide written notice advising that person of the reason for the refusal and that the Department may request such information.

DATES: *Effective Date:* This exemption is effective as of January 16, 2007.

Written Comments

In the Notice of Proposed Exemption (76 FR 14083, March 15, 2011)(the Notice), the Department invited all interested persons to submit written comments and requests for a hearing on the proposed exemption within forty (40) days of the date of the publication of such Notice in the **Federal Register**. All comments and requests for a hearing from interested persons were due by April 24, 2011. However, KKDC required additional time to mail the Notice to interested persons. Therefore, the Department extended the comment period until May 15, 2011.

During the comment period, the Department received one written comment and no requests for a hearing. KKDC submitted the comment on March 31, 2011 that it supplemented by e-mails dated April 19, 2011 and April 21, 2011.

In its comment, KKDC stated that the proposed exemption should be extended to include PwC and Mr. Phalen, the former Chief Financial Office of KKDI and a member of the Plans' Investment Committee. Both were parties to the Securities Litigation and parties in interest with respect to the Plans. In regard to PwC and Mr. Phalen, the KKDC asserts the following:

> It is possible that each Plan's (A) failure to opt of the [Securities Litigation], and any corresponding release of claims thereby effected, and (B) subsequent filing of a Proof of Claim and Release in favor of parties in interest KKDC, Phalen and PwC, in exchange for the Plan's right to receive its pro rata portion of the settlement proceeds in the Securities Litigation could have resulted in a violation of [the] prohibited transaction restrictions of ERISA and the Code. Notwithstanding the fact that the release of KKDC, Phalen, and PwC could each be viewed as a prohibited transaction, the proposed relief published in the **Federal Register** on March 15, 2011 provides an exemption only with respect to the release of KKDC, and leaves open the possibility that the releases of Phalen and PwC are

prohibited transactions with respect to the Plans.

KKDC further explains that the Plans' decision to enter into the Settlement Agreement to grant the releases of claims against the party in interest defendants was primarily based on the advice of Independent Fiduciary Services (IFS), the independent fiduciary for the Plans. Based on IFS' conclusions and the Department's determination that it was appropriate to grant an exemption for the Plans' release of claims against KKDC, KKDC explains that it is important that similar exemptive relief be provided with respect to the Plans' release of claims against PwC and Mr. Phalen.

If the exemption is not extended to these parties, KKDC believes the Plans' participation in the settlement of the Securities Litigation would have to be reversed and the Plans would be required to return their share of the settlement proceeds received. Additionally, KKDC notes that the Plans would lose a significant economic benefit if compelled to pursue separate litigation on this matter.

In response to this comment, the operative language of this exemption has been amended accordingly. The Department notes that the sentence in the Notice identifying PwC and Mr. Phalen as party in interest defendants was inadvertently omitted from the Notice. In this regard, the last sentence of the first paragraph of Representation 6 of the Notice, located in the third column of page 14085, should have read: ''The class action defendants (the Class Defendants) included KKDC, PwC, and Mr. Phalen, who served as the Chief Financial Officer of KKDI and a member of each Plan's committee.'' Additionally, a new sentence should have been added to the end of the first paragraph of Representation 6 of the Notice located in the third column of page 14085, stating: ''With the exception of KKDI, Mr. Phalen and PwC, none of the other Class Defendants was a party in interest with respect to the Plans.'' The Department, therefore, wishes to clarify that the requested relief includes all the party in interest Class Defendants with respect to the Securities Litigation. Furthermore, although the Department has determined that the exemption sufficiently covers the potential prohibited transaction engaged by KKDC in its capacity as a fiduciary, it does not provide exemptive relief for any prohibited transactions that resulted from the events leading to the filing of the Securities Litigation.

Accordingly, after giving full consideration to the entire record, including the KKDC written comment and supplemental statements, the Department has determined to grant the exemption as clarified herein. For a more complete statement of the facts and representations supporting the Department's decision to grant this exemption, refer to the Notice published on March 15, 2011 at 76 FR 14083.

FOR FURTHER INFORMATION CONTACT: Mr. Anh-Viet Ly of the Department at (202) 693–8648. (This is not a toll-free number.)

The United Brotherhood of Carpenters Pension Fund (the Plan), Located in Las Vegas, Nevada, [Prohibited Transaction Exemption 2011–11; Exemption Application No. D–11634].

Exemption

The restrictions of sections 406(a)(1)(A), (D) and 406(b)(2) of the Act and the sanctions resulting from the application of section 4975(c)(1)(A) and (D) of the Code, shall not apply to the proposed sale (Sale) of a 10.89 acre parcel of real property (the Parcel), which is part of larger parcel of real property (the Nevada Property), from the Plan-owned Bermuda Hidden Well, LLC to the Southwest Regional Council of Carpenters, a party in interest with respect to the Plan; provided that the following conditions are satisfied:

(a) The terms and conditions of the Sale are at least as favorable to the Plan as those obtainable in an arm's length transaction with an unrelated party;

(b) The Sale is a one-time transaction for cash;

(c) As consideration, the Plan receives the greater of $5,383,577, or the fair market value of the Parcel as determined by a qualified, independent appraiser (the Appraiser) in an appraisal of the Nevada Property, which is updated on the date of Sale;

(d) The Plan pays no commissions, costs or fees with respect to the Sale, except for customary closing costs and 50% of certain rental credits that are paid to unrelated parties; and

(e) The Plan fiduciaries review and approve the methodology used by the Appraiser, ensure that such methodology is properly applied in determining the fair market value of the Parcel, and also determine whether it is prudent to go forward with the proposed transaction.

For a more complete statement of the facts and representations supporting the Department's decision to grant this exemption, refer to the notice of proposed exemption published on May 5, 2011 at 76 FR 25714.

FOR FURTHER INFORMATION CONTACT: Mr. Anh-Viet Ly of the Department at (202) 693–8648. (This is not a toll-free number.)

Verizon Communications, Inc. (Verizon) and Cellco Partnership, doing business as Verizon Wireless (Verizon Wireless; collectively, the Applicants), Located in Basking Ridge, New Jersey, [Prohibited Transaction Exemption 2011–12; Exemption Application Nos. L–11651 and L–11652].

Exemption

The restrictions of sections 406(a) and (b) of the Act shall not apply to the reinsurance of risks and the receipt of premiums therefrom by Exchange Indemnity Company (EIC), a wholly-owned subsidiary of Verizon, in connection with an insurance contract sold by Prudential Life Insurance Company (Prudential) or any successor insurance company to Prudential which is unrelated to Verizon, to provide group-term life insurance to certain employees and retirees of Verizon and Verizon Wireless under The Plan for Group Insurance maintained by Verizon and the Verizon Wireless Health and Welfare Benefits Plan maintained by Verizon Wireless (collectively, the Plans), provided the following conditions are met:

(a) EIC—

(1) Is a party in interest with respect to the Plan by reason of a stock or partnership affiliation with Verizon that is described in section 3(14)(E) or (G) of the Act,

(2) Is licensed to sell insurance or conduct reinsurance operations in at least one State as defined in section 3(10) of the Act, (3) Has obtained a Certificate of Authority from the Insurance Commissioner of its domiciliary state which has neither been revoked nor suspended,

(4)(A) Has undergone and shall continue to undergo an examination by an independent certified public accountant for its last completed taxable year immediately prior to the taxable year of the reinsurance transaction; or

(B) Has undergone a financial examination (within the meaning of the law of its domiciliary State, Vermont) by the Insurance Commissioner of Vermont within 5 years prior to the end of the year preceding the year in which the reinsurance transaction occurred, and

(5) Is licensed to conduct reinsurance transactions by a State whose law requires that an actuarial review of reserves be conducted annually by an independent firm of actuaries and reported to the appropriate regulatory authority;

(b) The Plans pay no more than adequate consideration for the insurance contracts;

(c) In subsequent years, the formula used to calculate premiums by Prudential or any successor insurer will be similar to formulae used by other insurers providing comparable coverage under similar programs. Furthermore, the premium charge calculated in accordance with the formula will be reasonable and will be comparable to the premium charged by the insurer and its competitors with the same or a better rating providing the same coverage under comparable programs;

(d) The Plans only contract with insurers with a rating of A or better from A.M. Best Company. The reinsurance arrangement between the insurer and EIC will be indemnity insurance only, *i.e.,* the insurer will not be relieved of liability to the Plans should EIC be unable or unwilling to cover any liability arising from the reinsurance arrangement;

(e) No commissions, costs or other expenses are paid with respect to the reinsurance of such contracts; and

(f) For each taxable year of EIC, the gross premiums and annuity considerations received in that taxable year by EIC for life and health insurance or annuity contracts for all employee benefit plans (and their employers) with respect to which EIC is a party in interest by reason of a relationship to such employer described in section 3(14)(E) or (G) of the Act does not exceed 50% of the gross premiums and annuity considerations received for all lines of insurance (whether direct insurance or reinsurance) in that taxable year by EIC. For purposes of this condition (f):

(1) the term ''gross premiums and annuity considerations received'' means as to the numerator the total of premiums and annuity considerations received, both for the subject reinsurance transactions as well as for any direct sale or other reinsurance of life insurance, health insurance or annuity contracts to such plans (and their employers) by EIC. This total is to be reduced (in both the numerator and the denominator of the fraction) by experience refunds paid or credited in that taxable year by EIC.

(2) all premium and annuity considerations written by EIC for plans which it alone maintains are to be excluded from both the numerator and the denominator of the fraction.

For a more complete statement of the facts and representations supporting the Department's decision to grant this exemption, refer to the notice of proposed exemption published on May 5, 2011 at 76 FR 25721.

FOR FURTHER INFORMATION CONTACT: Gary H. Lefkowitz of the Department, telephone (202) 693–8546. (This is not a toll-free number.)

General Information

The attention of interested persons is directed to the following:

(1) The fact that a transaction is the subject of an exemption under section 408(a) of the Act and/or section 4975(c)(2) of the Code does not relieve a fiduciary or other party in interest or disqualified person from certain other provisions to which the exemption does not apply and the general fiduciary responsibility provisions of section 404 of the Act, which among other things require a fiduciary to discharge his duties respecting the plan solely in the interest of the participants and beneficiaries of the plan and in a prudent fashion in accordance with section 404(a)(1)(B) of the Act; nor does it affect the requirement of section 401(a) of the Code that the plan must operate for the exclusive benefit of the employees of the employer maintaining the plan and their beneficiaries;

(2) This exemption is supplemental to and not in derogation of, any other provisions of the Act and/or the Code, including statutory or administrative exemptions and transactional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction; and

(3) The availability of this exemption is subject to the express condition that the material facts and representations contained in the application accurately describes all material terms of the transaction which is the subject of the exemption.

Signed at Washington, DC this 4th day of August, 2011.

Ivan Strasfeld,

Director of Exemption Determinations, Employee Benefits Security Administration, U.S. Department of Labor.

[FR Doc. 2011–20342 Filed 8–10–11; 8:45 am]

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DEPARTMENT OF LABOR

Employee Benefits Security Administration

Proposed Exemptions From Certain Prohibited Transaction Restrictions

AGENCY: Employee Benefits Security Administration, Labor.

ACTION: Notice of Proposed Exemptions.

SUMMARY: This document contains notices of pendency before the Department of Labor (the Department) of proposed exemptions from certain of the prohibited transaction restrictions of the Employee Retirement Income Security Act of 1974 (ERISA or the Act) and/or the Internal Revenue Code of 1986 (the Code). This notice includes the following proposed exemptions: D–11601, BB&T Asset Management, Inc. (BB&T AM); and D–11661, Bayer Corporation (Bayer or the Applicant) *et al.*]

DATES: All interested persons are invited to submit written comments or requests for a hearing on the pending exemptions, unless otherwise stated in the Notice of Proposed Exemption, within 45 days from the date of publication of this **Federal Register** Notice.

ADDRESSES: Comments and requests for a hearing should state: (1) The name, address, and telephone number of the person making the comment or request, and (2) the nature of the person's interest in the exemption and the manner in which the person would be adversely affected by the exemption. A request for a hearing must also state the issues to be addressed and include a general description of the evidence to be presented at the hearing.

All written comments and requests for a hearing (at least three copies) should be sent to the Employee Benefits Security Administration (EBSA), Office of Exemption Determinations, Room N–5700, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210. Attention: Application No. ________, stated in each Notice of Proposed Exemption. Interested persons are also invited to submit comments and/or hearing requests to EBSA via e-mail or FAX. Any such comments or requests should be sent either by e-mail to: *moffitt.betty@dol.gov,* or by FAX to (202) 219–0204 by the end of the scheduled comment period. The applications for exemption and the comments received will be available for public inspection in the Public Documents Room of the Employee Benefits Security Administration, U.S. Department of Labor, Room N–1513, 200 Constitution Avenue, NW., Washington, DC 20210.

Warning: If you submit written comments or hearing requests, do not include any personally-identifiable or confidential business information that you do not want to be publicly-disclosed. All comments and hearing requests are posted on the Internet exactly as they are received, and they can be retrieved by most Internet search engines. The Department will make no deletions, modifications or redactions to the comments or hearing requests received, as they are public records.

SUPPLEMENTARY INFORMATION:

Notice to Interested Persons

Notice of the proposed exemptions will be provided to all interested persons in the manner agreed upon by the applicant and the Department within 15 days of the date of publication in the **Federal Register**. Such notice shall include a copy of the notice of proposed exemption as published in the **Federal Register** and shall inform interested persons of their right to comment and to request a hearing (where appropriate).

The proposed exemptions were requested in applications filed pursuant to section 408(a) of the Act and/or section 4975(c)(2) of the Code, and in accordance with procedures set forth in 29 CFR part 2570, Subpart B (55 FR 32836, 32847, August 10, 1990). Effective December 31, 1978, section 102 of Reorganization Plan No. 4 of 1978, 5 U.S.C. App. 1 (1996), transferred the authority of the Secretary of the Treasury to issue exemptions of the type requested to the Secretary of Labor. Therefore, these notices of proposed exemption are issued solely by the Department.

The applications contain representations with regard to the proposed exemptions which are summarized below. Interested persons are referred to the applications on file with the Department for a complete statement of the facts and representations.

BB&T Asset Management, Inc. (BB&T AM)

Located in Winston-Salem, North Carolina

[Application No. D–11601]

Proposed Exemption

Based on the facts and representations set forth in the application, the Department is considering granting the following exemption under the authority of Code section 4975(c)(2), and in accordance with the procedures set forth in 29 CFR part 2570, subpart B (55 FR 32836, 32847, August 10, 1990), as follows:

Section I: Covered Transactions

If the proposed exemption is granted, the sanctions resulting from the application of Code section 4975, by reason of Code section 4975(c)(1)(A) and (C)–(F), shall not apply, effective April 30, 2002 until December 27, 2005, to (1) Directed trades by BB&T AM and its successors in interest (together, the Applicant) as an investment manager and investment adviser to certain plans, subject to Code section 4975, but not subject to Title I of ERISA (the IRAs), which resulted in the IRAs purchasing or selling securities from Scott & Stringfellow, LLC (S&S), an affiliated broker-dealer of BB&T AM (collectively, the Transactions); and (2) compensation paid by the IRAs to S&S in connection with the Transactions (the Transaction Compensation).

This proposed exemption is subject to the conditions set forth below in Sections II and III.

Section II: Specific Conditions

(a) The Transactions and the Transaction Compensation were corrected (1) pursuant to the requirements set forth in the Department's Voluntary Fiduciary Correction Program (the VFC Program) [1] and (2) in a manner consistent with those transactions described in the Applicant's VFC Program application, dated January 22, 2010 (the VFC Program Application), that were substantially similar to the Transactions but that involved plans described in Code section 4975(e)(1) and subject to Title I of ERISA (the Qualified Plan Transactions).

(b) The Applicant received a ''no-action letter'' from the Department in connection with the Qualified Plan Transactions described in the VFC Program Application.

(c) The fair market value of the securities involved in the Transactions was determined in accordance with Section 5 of the VFC Program.

(d) The terms of the Transactions and the Transaction Compensation were at least as favorable to the IRAs as the terms generally available in arm's length transactions between unrelated parties.

(e) The Transactions and Transaction Compensation were not part of an agreement, arrangement or understanding designed to benefit a disqualified person, as defined in Code section 4975(e)(2).

(f) The Applicant did not take advantage of the relief provided by the VFC Program and Prohibited Transaction Exemption 2002–51 [2] (PTE 2002–51) for three (3) years prior to the date of the Applicant's submission of the VFC Program Application.

Section III: General Conditions

(a) The Applicant maintains, or causes to be maintained, for a period of six (6) years from the date of any Transaction such records as are necessary to enable the persons described in Section III(b)(1), to determine whether the conditions of this exemption have been met, except that:

(1) A separate prohibited transaction shall not be considered to have occurred if, due to circumstances beyond the control of Applicant, the records are lost or destroyed prior to the end of the six-year period; and

(2) No disqualified person with respect to an IRA, other than Applicant, shall be subject to excise taxes imposed by Code section 4975, if such records are not maintained, or are not available for examination, as required by Section III(b)(1).

(b)(1) Except as provided in Section III(b)(2), the records referred to in Section III(a) are unconditionally available at their customary location for examination during normal business hours by:

(A) Any duly authorized employee or representative of the Department, the Internal Revenue Service, or the Securities and Exchange Commission;

(B) Any fiduciary of any IRA that engaged in a Transaction, or any duly authorized employee or representative of such fiduciary; or

(C) Any owner or beneficiary of an IRA that engaged in a Transaction or a representative of such owner or beneficiary.

(2) None of the persons described in Sections III(b)(1)(B) and (C) shall be authorized to examine trade secrets of Applicant, or commercial or financial information which is privileged or confidential.

(3) Should Applicant refuse to disclose information on the basis that such information is exempt from disclosure, Applicant shall, by the close of the thirtieth (30th) day following the request, provide a written notice advising that person of the reasons for the refusal and that the Department may request such information.

Effective Date: If granted, this proposed exemption will be effective from April 30, 2002 until December 27, 2005.

Summary of Facts and Representations

1. The Applicant consists of BB&T AM and its successors in interest, BB&T AM LLC and Sterling Capital Management LLC (SCM LLC). BB&T AM was a wholly owned subsidiary of BB&T Corporation, a large financial institution, headquartered in Winston-Salem, North Carolina. On September 9, 2010, BB&T AM was reorganized as BB&T AM LLC. On October 1, 2010, BB&T AM LLC was merged into SCM LLC.

[1] 71 FR 20262 (April 19, 2006).

[2] 71 FR 20135 (April 19, 2006).

On September 30, 2010, BB&T AM LLC had total assets under management of $17.3 billion. As of December 31, 2010, BB&T Corporation had total assets of approximately $157 billion.

2. Virginia Investment Counselors, Inc. (VIC) of Norfolk, Virginia is a former asset manager and investment adviser to the IRAs and certain qualified plans described in Code section 4975(e)(1) and subject to Title I of ERISA (collectively, the Plans). In such capacity, VIC was granted discretionary investment authority with respect to such Plans by the Plans' respective plan administrators and beneficial owners. On April 30, 2002, VIC was acquired by the Applicant, *i.e.,* BB&T AM, (the Corporate Transaction) and, thereafter, became a division of the Applicant. Prior to the date of the Corporate Transaction, VIC was an unrelated party to the Applicant.

3. S&S is a registered broker-dealer. At all times relevant hereunder, S&S was a wholly owned subsidiary of BB&T Corporation.

4. Prior to the Corporate Transaction, VIC directed trades that resulted in the Plans purchasing securities from the inventory of S&S or selling securities to S&S. Because VIC and S&S were unrelated parties at that time, these types of transactions were not prohibited under ERISA or the Code.

5. Following the consummation of the Corporate Transaction, from April 30, 2002 to the close of 2006, trading between VIC (now as a division of BB&T AM) and S&S with respect to the Plans continued in the same arm's length manner as before the Corporate Transaction. Such continuation was inadvertent, and it resulted solely from VIC's failure to identify S&S as a disqualified person. During this time period, the Applicant directed 103 IRAs to purchase bonds from S&S 185 times, for an aggregate purchase price of $3,256,925 (the Bond Purchase Transactions), and 10 IRAs to sell bonds to S&S 13 times, for an aggregate sales price of $147,640 (the Bond Sale Transactions). The Applicant also directed one transaction in which an IRA purchased a stock from S&S, for a purchase price of $29,222 (the Stock Purchase Transaction) and 4 Transactions in which an IRA sold stock to S&S, for a sales price of $133,209 (the Stock Sale Transactions and, collectively, the Bond Purchase Transactions, the Bond Sale Transactions, the Stock Purchase Transaction and Stock Sale Transactions being the Transactions). The last Transaction occurred on December 27, 2005.

6. The Transactions caused the payment of compensation to S&S (Transaction Compensation). With respect to Bond Purchase Transactions and Bond Sale Transactions, S&S' compensation was reflected in the purchase price of the applicable bond. That is, S&S was compensated only through a ''mark-up'' of the bond price. With respect to the Stock Purchase Transaction and the Stock Sale Transactions, separate, identifiable commissions and fees totaling $829 were charged by S&S.

7. The Applicant seeks relief with respect to the Transactions and with respect to the payment of the Transaction Compensation. Specifically, the Applicant believes that: (a) The purchase and sale of securities between the IRAs and S&S was prohibited by Code section 4975(c)(1)(A); (b) S&S' provision of brokerage services to the IRAs was prohibited by Code section 4975(c)(1)(C); (c) both the Transactions and the payment of Transaction Compensation were prohibited by Code section 4975(c)(1)(D); and (d) the decision by VIC, in its role as fiduciary, to cause the IRAs to enter into the Transactions and pay the Transaction Compensation to S&S was prohibited by Code section 4975(c)(1)(E) and (F). The Applicant believes that if the proposed exemption is not granted the IRAs would be subject to hardship resulting from the uncertainty of not having the prohibited transactions outlined herein resolved. Further, the IRAs would be subject to additional hardship if the proposed exemption is denied as a result of the resultant uncertainty regarding the correction methodology applied by the Applicant.

8. The Applicant represents that as soon as the Transactions and the Qualified Plan Transactions were discovered it began the correction process. The Applicant corrected the Qualified Plan Transactions pursuant to the requirements set forth in the VFC Program. The Applicant filed a VFC Program Application, dated January 22, 2010, with respect to the Qualified Plan Transactions, and it received a no-action letter from the Department, dated August 31, 2010, with respect to the Qualified Plan Transactions.

9. While the Qualified Plan Transactions were properly corrected under the VFC Program, the Applicant was not able to similarly correct the Transactions and the Transaction Compensation. Despite being substantially similar to the Qualified Plan Transactions, the Transactions and the Transaction Compensation are ineligible for relief under the VFC Program and PTE 2002–51 because they involved IRAs which are not covered under Title I of ERISA. The Applicant, however, believes that granting relief pursuant to the proposed exemption is consistent with the Department's statement that ''[the VFC Program] does not foreclose its future consideration of individual exemption requests of transactions involving IRAs that are outside the scope of relief provided by the VFC Program and the class exemption under circumstance where, for example, a financial institution received a no action letter applicable to plans subject to [the VFC Program] for a transaction(s) that involved both plans and IRAs.'' 71 FR 20135 (April 19, 2006).

10. Consistent with the Department's statement, the Applicant represents that the Transactions were corrected pursuant to the requirements set forth in the VFC Program and in a manner consistent with the Applicant's VFC Program Application, with such representation made in the Applicant's exemption application, dated January 22, 2010, under penalty of perjury. In this regard, the Applicant corrected the Transactions in the manner generally described below:

(a) With respect to the Bond Purchase Transactions, since bonds are debt instruments, the Applicant corrected the Bond Purchase Transactions, based on economic similarity to a loan transaction correction, under the procedures for loans made at a fair market interest rate pursuant to Section 7.2 of the VFC Program. The correction method for a loan, which is set forth in Section 7.2(a)(2) of the VFC program, is for the party in interest to pay back the loan in full, including any prepayment penalties. Section 7.2(a)(2) also requires that an independent commercial lender confirm that the loan was made at a fair market interest rate for a loan with similar terms to a borrower of similar creditworthiness. The Applicant represents that it satisfied the requirements under Section 7.2(a)(3) of the VFC Program by means of a written report prepared by Independent Fiduciary Services, Inc. (IFS), an independent fiduciary services firm, which among other things, compared the actual purchase price of transactions to a written confirmation of the market price on the day of each Bond Purchase Transaction (or the next date a price was available) obtained from two independent pricing services (Standard & Poor's JJ Kenny Pricing Service and Estate Valuation and Pricing Systems) selected by IFS.

(b) With respect to the Bond Sale Transactions and Stock Sale Transactions, the Applicant corrected these Transactions under the procedures for sale of an asset to a party in interest under Section 7.4(b) of the VFC Program. Section 7.4(b)(2)(i) of the VFC Program generally requires that the asset be repurchased from the party in interest at the lower of the price for which it originally sold the property or the fair market value (FMV) of the property at the time of correction. As an alternative, section 7.4(b)(2)(ii) of the VFC Program provides that a plan may receive a cash settlement of the ''Principal Amount,'' defined as the excess of the FMV of the asset at the time of sale over the sales price, plus ''Lost Earnings,'' which is generally defined as the approximate amount that would have been earned by a plan on the Principal Amount but for the prohibited transaction, provided, that, an independent fiduciary determines that the applicable Plan would receive a greater benefit than by repurchase.

It was impractical or impossible to repurchase the bonds in the Bond Sale Transactions. This was due to the fact that some of the bonds were no longer available because they had been called, matured, were thinly traded or not in the inventory of the Applicant or its affiliates. Further, because the Applicant no longer served as investment adviser to the majority of the IRAs at the time of correction, the Applicant did not believe it was in a position to effect the repurchase of the bonds by the IRAs. Therefore, the Applicant corrected the Bond Sale Transaction by paying the IRAs the Principal Amount plus Lost Earnings from the time of the Transaction.

For the Stock Sale Transactions, the IRA was given the option of repurchasing the stock at the price determined under Section 7.4(b) of the VFC Program or receiving a cash settlement amount of the greater of the cash settlement amount determined under Section 7.4(b) or the excess, if any, of the FMV of the stock as of the date of correction over the price for which it originally sold the stock (which is the economic equivalent to repurchasing the security at the price determined under Section 7.4(b) of the VFC Program).

(c) With respect to the Stock Purchase Transaction, the Applicant corrected the Stock Purchase Transaction under the procedures for the purchase of an asset from a party in interest pursuant to Section 7.4(a) of the VFC Program. Section 7.4(a) generally requires that the asset be sold back to the party in interest or to a person who is not a party in interest for a price at least equal to the greater of (1) The FMV of the asset at the time of resale, without reduction for the costs of sale, or (2) the original purchase price, plus Lost Earnings. As an alternative, the asset may be retained along with a payment in the amount of the difference between the original purchase price paid and the FMV of the asset at the time of the purchase, plus lost earnings. Since the IRA involved in the Stock Purchase Transaction was no longer a client of the Applicant at the time of correction, the IRA was deemed to have disposed of the stock at the FMV of the stock on the date the IRA closed its account with the Applicant. The IRA was paid a corrective payment in the amount of the greater of (1) the original purchase price, plus Lost Earnings calculated through the time the IRA's account closed with the Applicant, less the FMV of the stock at the time of the deemed disposition or (2) any excess of the original purchase price over the FMV of the stock at the time of purchase, plus Lost Earnings on such amount calculated through the date of correction.

11. With respect to the Applicant's correction of the Transactions, (a) The Applicant took into account all transaction costs (*e.g.,* Transaction Compensation), if any, paid by the IRAs in calculating the applicable Principal Amount as defined under the VFC Program; (b) Section 5 of the VFC Program was followed to make fair market value determinations; and (c) the Applicant engaged an independent certified public accounting firm to calculate the appropriate correction payments. Since the bonds in the Bond Sale Transactions did not have a generally recognized FMV, the FMVs of the bonds were determined pursuant to a written report prepared by IFS comparing the actual purchase price of transactions to written confirmations of the market price on the applicable date from independent pricing services selected by IFS. For the Stock Purchase Transaction and the Stock Sale Transactions, the FMV of the stocks involved were determined using the average value of the security on the generally recognized market for the security on the date of the applicable transaction as reported by an independent pricing service.

12. The Applicant represents that ''Restoration of Profits,'' as defined under the VFC Program, did not apply with respect to the Transactions because no amounts were used for a specific purpose such that a profit was determinable.

13. The Applicant represents that it sent each IRA involved in a Transaction a letter describing the Transaction(s) applicable to the IRA and, where appropriate, a check for the correction amount.

14. The Applicant believes that the Transactions were inadvertent and resulted in the IRAs receiving at least a market yield-to-maturity with respect to the Bond Purchase Transactions or at least the market price with respect to Bond Sale Transactions, Stock Purchase Transaction and Stock Sale Transactions because the Applicant and S&S operated as independently managed entities and, as a result of the foregoing, the terms of the Transactions were at least as favorable to the IRAs as the terms generally available in arm's length transactions between unrelated parties.

15. The Applicant represents that it has not taken advantage of the relief provided by the VFC Program and PTE 2002–51 for the three (3) years prior to the date of the Applicant's submission of the VFC Program Application, and that the Transactions were not part of an agreement, arrangement or understanding designed to benefit a disqualified person.

16. The Applicant represents that the proposed exemption is: (a) Administratively feasible because the Applicant has corrected the Transactions pursuant to the requirements set forth in the VFC Program, has obtained relief under the VFC Program for the Qualified Plan Transactions and has put procedures in place to ensure that no similar Transactions occur in the future; (b) in the interests of the affected IRAs and their owners and beneficiaries because the Transactions have been corrected pursuant to the procedures set forth in the VFC Program, which are designed to ensure that the corrections are made in a manner that is in the interests of the IRAs and their owners and beneficiaries; and (c) protective of the rights of the owners and beneficiaries of the IRAs because the requested relief is only with respect to past transactions, which the Applicant believes were effectively conducted on an arm's length basis, that have already been effectively unwound pursuant to the requirements set forth in the VFC Program.

17. In summary, the Applicant represents that the Transactions and the Transaction Compensation satisfy the statutory criteria for an administrative exemption contained in Code section 4975(c)(2) because, among other things: (a) The Transactions and Transaction Compensation were substantially similar to the Qualified Plan Transactions; (b) the Transactions and Transaction Compensation were corrected pursuant to the requirements set forth in the VFC Program and in a manner similar to those described in the

Applicant's VFC Program Application; (c) the Applicant received a ''no-action letter'' from the Department in connection with Applicant's VFC Program Application; (d) the FMVs of the IRA bonds and stocks involved in the Transactions were determined in accordance with Section 5 of the VFC Program; (e) the terms of the Transactions and the Transaction Compensation were at least as favorable to the IRAs as the terms generally available in arm's-length transactions between unrelated parties; (f) the Transactions and Transaction Compensation were not part of an agreement, arrangement or understanding designed to benefit a disqualified person; and (g) the Applicant did not take advantage of the relief provided by the VFC Program and PTE 2002–51 for three (3) years prior to the date of the Applicant's submission of the VFC Program Application.

FOR FURTHER INFORMATION CONTACT: Mr. Brian Shiker of the Department, telephone (202) 693–8552. (This is not a toll-free number.)

Bayer Corporation (Bayer or the Applicant)

Located in Pittsburgh, PA

[Application No. D–11661]

Proposed Exemption

The Department is considering granting an exemption under the authority of section 408(a) of the Act and section 4975(c)(2) of the Code and in accordance with the procedures set forth in 29 CFR part 2570, subpart B (55 FR 32836, 32847, August 10, 1990).[3] If the exemption is granted, the restrictions of sections 406(a)(1)(A) and 406(b)(1) and (b)(2) of the Act and the sanctions resulting from the application of section 4975(c)(1)(A) and (E) of the Code, shall not apply, effective September 15, 2011, to the one-time, in kind contribution (the Contribution) of certain U.S. Treasury Bills (the Securities) to the Bayer Corporation Pension Plan (the Plan) by the Applicant, a party in interest with respect to the Plan; provided that the following conditions are satisfied:

(a) In addition to the Securities, Bayer contributes to the Plan, by September 15, 2011, such cash amounts as are needed to allow the Plan to attain an Adjusted Funding Target Attainment Percentage (AFTAP) of 90%, as determined by the Plan's actuary (the Actuary);

(b) The fair market value of the Securities is determined by Bayer on the date of the Contribution (the Contribution Date) based on the average of the bid and ask prices as of 3 p.m. Eastern Time, as quoted in The Wall Street Journal on the Contribution Date;

(c) The Securities represent less than 20% of the Plan's assets.

(d) The terms of the Contribution are no less favorable to the Plan than those negotiated at arm's length under similar circumstances between unrelated parties;

(e) The Plan pays no commissions, costs or fees with respect to the Contribution; and

(f) The Plan fiduciaries review and approve the methodology used to value to the Securities and ensure that such methodology is properly applied in determining the fair market value of the Securities.

Effective Date: If granted, this proposed exemption will be effective as of September 15, 2011.

Summary of Facts and Representations

Parties to the Proposed Transaction

1. Bayer, headquartered in Pittsburgh, PA, is a holding company for the business interests of Bayer AG in the United States. Bayer AG is an international health care, nutrition and high-tech materials group based in Leverkusen, Germany. In North America, Bayer had 2010 net sales of approximately $10.86 billion and employed 16,400 at year end. Bayer sponsors the Plan.

2. The Plan is a defined benefit pension plan. As of January 1, 2010, which is the most recent date for which participant and Plan financial information are available, the Plan had 34,766 participants and beneficiaries and total assets of $2,126,444,442. The Plan also had total liabilities of $2,354,042,112 as of this date.

3. The Bayer Corporation Master Trust (the Master Trust) holds the assets of the Plan and five other defined benefit plans (collectively, the ''Plans'') sponsored by Bayer. The Bayer Trust Investment Committee (the Committee) is the named fiduciary with respect to the Master Trust. Bayer serves as the Plan administrator for the Plans. Mellon Bank, N.A. serves as the trustee for the Plans.

Plan Funding for Plan Year 2011

4. The Applicant represents that the Plans participating in the Master Trust are historically funded on an AFTAP funding level ranging from 90% to 96%. In an actuarial report (the Actuarial Report) dated September 30, 2010, Towers Watson, the Plan's Actuary, stated that the Plan's AFTAP as of January 1, 2009 was 90% and as of January 1, 2010, it was 90.08%.

5. The Actuarial Report also provided for the Plan's minimum contribution payment for January 14, 2011 and September 15, 2011. In compliance with the Actuarial Report, Bayer made its scheduled minimum cash contribution payment to the Plan of $3,499,721 as of January 11, 2011. Should Bayer make its next scheduled required minimum cash contribution payment of $12,953,054 on September 15, 2011, the Applicant notes that the Plan's AFTAP would fall below 80% (as measured on January 1, 2011). The Applicant explains that because of a prior year loss in 2008 of 28% to the Plan, the Plan's AFTAP would fall below 80% if Bayer makes only its required minimum contribution for 2011.

6. As a result, the Applicant explains that the benefit restrictions of sections 206(g) of the Act and 436(d)(3) of the Code[4] would be triggered upon the Actuary's certification of the 2011 Actuarial Report. Such restrictions would limit Plan lump sum payments to 50% of the value of a participant's benefit and would defer Plan Social Security level income payouts. These measures could harm current Plan participants nearing benefit commencement.

7. The Applicant represents that these benefit restrictions would affect a significant number of Plan participants. With respect to lump sum payments, the Applicant states that approximately 3,500 active and deferred participants in the Plan are eligible to elect a lump sum upon either retirement or the time of benefit commencement. With respect to Social Security level income benefit elections, the Applicant explains that 5,100 active and deferred vested Plan participants are eligible to make such elections upon retirement or at the time of benefit commencement.

Contribution of the Securities

8. On December 17, 2010, Bayer, in its corporate capacity, purchased the Securities for $299,302,083.30. The CUSIP number for the Securities is 9127952P5. The Applicant represents

[3] For purposes of this proposed exemption, references to the provisions of Title I of the Act, unless otherwise specified, refer also to the corresponding provisions of the Code.

[4] Section 436(d)(3)(C) of the Code and section 206(g)(3)(C) of the Act provide that if the AFTAP is at least 60% but less than 80%, a single employer defined benefit plan may not pay a prohibited payment to the extent the payment exceeds the lesser of (1) 50% of the amount of the payment that would be paid if the restriction did not apply, or (2) the present value, determined under guidance provided by the Pension Benefit Guaranty Corporation, of the maximum guarantee with respect to the participant under section 4022 of the Act.

that Bayer purchased the Securities on the open market through its broker, Citizens Investment Services, an unrelated party. The Securities will mature on November 17, 2011, with a value of $300,000,000.00 in six denominations each of $50,000,000. The Securities have an effective annual yield of 0.25%. The Securities also represent approximately 12.2% of the Plan's assets.

On January 21, 2011, the Committee determined that contributing the Securities to the Plan on a one-time basis would benefit the Plan's participants. The Committee also determined that the Securities would give the Master Trust a safe and liquid investment without additional transactions costs, would help maintain the Plan's funding level and would prevent potential benefit restrictions mentioned above. Furthermore, the proposed Contribution is substantially similar to contributing cash since the Securities are considered cash equivalents.

9. The proposed Contribution would also benefit Bayer by allowing it to issue public debt at a lower cost. The Applicant states that its credit rating impacts the interest rate payable when it borrows. The Applicant represents that a full cash contribution, which is reported on its financial statements as a use of operating gross cash flow, would have a negative impact on the financial ratios calculated by credit rating agencies. If its credit rating is lowered, the Applicant explains that its cost of borrowing could substantially increase. However, unlike a full cash contribution to the Plan, the Applicant indicates that the proposed Contribution is not reported as a use of operating cash flow. Accordingly, the Applicant maintains that the proposed Contribution would not have a negative impact on its credit rating.

Valuation of the Securities

10. As of March 31, 2011, the Applicant represents that the fair market value of the Securities was $299,451,000. The Applicant states that it applied the average bid and ask price of .183%, as of 3 p.m. on March 31, 2011, as quoted in The Wall Street Journal, to obtain a discount value of $549,000.00. The Applicant explains that it then applied the discount to the face value of the Securities at maturity to obtain $299,451,000, as the fair market value as of March 31, 2011.

11. The fair market value price of the Securities contributed to the Plan will be based on its value on the Contribution Date. The Applicant represents it will select the Contribution Date on which The Wall Street Journal publishes the bid and ask price for U.S. Treasury Bills that mature on November 17, 2011. The Applicant states that it will average the bid and ask price as of 3 p.m. Eastern Time, as published in The Wall Street Journal, to determine the appropriate discount. The Applicant also explains that it will then apply the discount to the Securities to determine the fair market value on the Contribution Date.

Request for Exemptive Relief

12. The Applicant requests exemptive relief from the Department for the proposed Contribution which represents an in kind contribution to the Plan from the Applicant, a party in interest, that would violate sections 406(a)(1)(A) of the Act. The Applicant, which is a fiduciary, is causing both a sale or exchange between a party and interest and the Plan prohibited by section 406(a)(1)(A) of the Act. The Applicant states that the proposed Contribution also would violate sections 406(b)(1) and (2) of the Act. The Applicant, as a fiduciary, is dealing with the assets of the Plan in its own interest or its own account in violation of 406(b)(1) of the Act and is acting in a capacity where its interests are adverse to the interest of the plan or the interests of its participants and beneficiaries in violation of 406(b)(2) of the Act.

Contribution Logistics

13. The Applicant represents that it is committed to making the proposed Contribution as of September 15, 2011. The Applicant represents that it will also make a cash contribution to the Plan, by September 15, 2011, to allow the Plan to attain an AFTAP of 90%, along with the Contribution of the Securities. This additional cash contribution to the Plan is presently estimated at $58 million. The Applicant will know the actual cash contribution amount when it receives the 2011 Actuarial Report from the Actuary. Furthermore, the Applicant represents that should the Plan sell the Securities prior to their maturity, Bayer will pay all costs or fees related to such sale.

Rationale for the Contribution

14. The Applicant represents that there are a number of reasons supporting the Contribution. In this regard, the Applicant states that the proposed Contribution is administratively feasible because it is a one time only transaction that would require no further action by the Department. Moreover, the Plan will pay no fees, commissions or costs in relation to the Contribution.

The Applicant states that the Contribution is in the interests of the Plan, its participants and beneficiaries because the Contribution and an estimated $58 million additional cash contribution will allow the Plan to attain a 90% AFTAP. As noted above, the Plan's required minimum contribution scheduled for September 15, 2011 is $12,953,054. The Securities with a value of $300,000,000 at maturity on November 17, 2011, would exceed the Plan's required minimum contribution by approximately $287 million. An additional cash contribution of approximately $58 million should allow the Plan to attain an AFTAP of 90%, when combined with the Securities. Accordingly, the Applicant states that the Contribution will avoid the benefit restrictions of section 206(g) of the Act and section 436(g) of the Code.

The Applicant further states that the Contribution would be protective of the Plan and its participants and beneficiaries. In this respect, the Applicant explains that the Contribution involves Securities that are cash equivalents and have a readily ascertainable fair market value. Moreover, the Applicant indicates that the Securities will mature within months of the Contribution Date. Should the Plan need to sell the Securities prior to their maturity, the Applicant represents that it will cover all transaction costs that are associated with such sale.

Summary

15. In summary, the Applicant represents that the Contribution will satisfy the statutory requirements for an exemption under section 408(a) of the Act because:

(a) In addition to the Securities, Bayer will contribute to the Plan, by September 15, 2011, such cash amounts as are needed to allow the Plan to attain an AFTAP of 90%, as determined by the Plan's actuary;

(b) The fair market value of the Securities will be determined by Bayer on the Contribution Date based on the average of the bid and ask prices as of 3 p.m. Eastern Time, as quoted in The Wall Street Journal on the Contribution Date;

(c) The Securities will represent less than 20% of the Plan's assets.

(d) The terms of the Contribution will be no less favorable to the Plan than those negotiated at arm's length under similar circumstances between unrelated parties;

(e) The Plan will pay no commissions, costs or fees with respect to the Contribution; and

(f) The Plan fiduciaries will review and approve the methodology used to value the Securities and ensure that such methodology is properly applied in determining the fair market value of the Securities.

Notice to Interested Parties

Notice of the proposed exemption will be given to interested persons within 5 days of the publication of the notice of proposed exemption in the **Federal Register**. The notice will be given to interested persons by first class mail or by return receipt requested electronic mail. Such notice will contain a copy of the notice of proposed exemption, as published in the **Federal Register**, and a supplemental statement, as required pursuant to 29 CFR 2570.43(b)(2). The supplemental statement will inform interested persons of their right to comment on and/or to request a hearing with respect to the pending exemption. Written comments and hearing requests are due within 40 days of the publication of the notice of proposed exemption in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Mr. Anh-Viet Ly of the Department at (202) 693–8648. (This is not a toll-free number.)

General Information

The attention of interested persons is directed to the following:

(1) The fact that a transaction is the subject of an exemption under section 408(a) of the Act and/or section 4975(c)(2) of the Code does not relieve a fiduciary or other party in interest or disqualified person from certain other provisions of the Act and/or the Code, including any prohibited transaction provisions to which the exemption does not apply and the general fiduciary responsibility provisions of section 404 of the Act, which, among other things, require a fiduciary to discharge his duties respecting the plan solely in the interest of the participants and beneficiaries of the plan and in a prudent fashion in accordance with section 404(a)(1)(b) of the Act; nor does it affect the requirement of section 401(a) of the Code that the plan must operate for the exclusive benefit of the employees of the employer maintaining the plan and their beneficiaries;

(2) Before an exemption may be granted under section 408(a) of the Act and/or section 4975(c)(2) of the Code, the Department must find that the exemption is administratively feasible, in the interests of the plan and of its participants and beneficiaries, and protective of the rights of participants and beneficiaries of the plan;

(3) The proposed exemptions, if granted, will be supplemental to, and not in derogation of, any other provisions of the Act and/or the Code, including statutory or administrative exemptions and transitional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction; and

(4) The proposed exemptions, if granted, will be subject to the express condition that the material facts and representations contained in each application are true and complete, and that each application accurately describes all material terms of the transaction which is the subject of the exemption.

Signed at Washington, DC, this 2nd day of August, 2011.

Ivan Strasfeld,

Director of Exemption Determinations, Employee Benefits Security Administration, U.S. Department of Labor.

[FR Doc. 2011–20341 Filed 8–10–11; 8:45 am]

BILLING CODE 4510–29–P

OFFICE OF NATIONAL DRUG CONTROL POLICY

Designation of ONDCP SES Performance Review Board Members

AGENCY: Office of National Drug Control Policy.

ACTION: Notice of Designation of ONDCP SES Performance Review Board.

Headings: Designation Pursuant of ONDCP SES Performance Review Board Pursuant to 5 CFR 4 30.310.

SUMMARY: The Director of the Office of National Drug Control Policy has appointed Patrick M. Ward, Robert Denniston, Michele Marx, and Jeffrey Teitz as members of the ONDCP SES Performance Review Board (PRB).

FOR FURTHER INFORMATION CONTACT: Please direct any questions to Briggitte LaFontant, Assistant for Personnel, Office of National Drug Control Policy, Executive Office of the President, Washington, DC 20502; (202) 395–6695.

Daniel R. Petersen,

Deputy General Counsel.

[FR Doc. 2011–20422 Filed 8–10–11; 8:45 am]

BILLING CODE 3180–W1–P

NATIONAL SCIENCE FOUNDATION

Notice of Permit Modification Issued Under the Antarctic Conservation Act of 1978

AGENCY: National Science Foundation.

ACTION: Notice of permit issued under the Antarctic Conservation of 1978, Public Law 95–541.

SUMMARY: The National Science Foundation (NSF) is required to publish notice of permits issued under the Antarctic Conservation Act of 1978. This is the required notice.

FOR FURTHER INFORMATION CONTACT: Nadene G. Kennedy, Permit Office, Office of Polar Programs, Rm. 755, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230.

SUPPLEMENTARY INFORMATION: On July 7, 2011, the National Science Foundation published a notice in the **Federal Register** of a permit application received. The permit was issued on August 8, 2011 to: James G. Bockheim; Permit No. 2012–004.

Nadene G. Kennedy,

Permit Officer.

[FR Doc. 2011–20409 Filed 8–10–11; 8:45 am]

BILLING CODE 7555–01–P

NATIONAL SCIENCE FOUNDATION

Notice of Permit Modification Received Under the Antarctic Conservation Act of 1978 (Pub. L. 95–541)

AGENCY: National Science Foundation.

ACTION: Notice of Permit Modification Request Received under the Antarctic Conservation Act of 1978, Public Law 95–541.

SUMMARY: The National Science Foundation (NSF) is required to publish a notice of requests to modify permits issued to conduct activities regulated under the Antarctic Conservation Act of 1978. NSF has published regulations under the Antarctic Conservation Act at Title 45 part 670 of the Code of Federal Regulations. This is the required notice of a requested permit modification.

DATES: Interested parties are invited to submit written data, comments, or views with respect to this permit application by September 12, 2011. Permit applications may be inspected by interested parties at the Permit Office, address below.

ADDRESS: Comments should be addressed to Permit Office, Room 755, Office of Polar Programs, National Science Foundation, 4201 Wilson Boulevard, Arlington, Virginia 22230.

FOR FURTHER INFORMATION CONTACT: Nadene G. Kennedy at the above address or (703) 292–7405.

SUPPLEMENTAL INFORMATION: The National Science Foundation, as directed by the Antarctic Conservation Act of 1978 (Pub. L. 95–541), as amended by the Antarctic Science, Tourism and Conservation Act of 1996, has developed regulations for the establishment of a permit system for various activities in Antarctica and designation of certain animals and certain geographic areas requiring special protection. The regulations establish such a permit system to designate Antarctic Specially Protected Areas.

DESCRIPTION OF PERMIT MODIFICATION REQUESTED: The Foundation issued a permit (2009–015) to Ron Naveen on August 25, 2008. The issued permit allows the applicant to regularly survey/census various sites in the Antarctic Peninsula, including some Antarctic Specially Protected Areas (ASPA's) as part of the ongoing Antarctic Site Inventory Project.

The applicant requests a modification to his permit to allow access to several ASPA's that have substantial penguin and seabird populations which are relevant to the analysis of population trends. The ASPA's the applicant wishes to potentially access are: ASPA 108–Green Island, ASPA 113–Litchfield Island, ASPA 140–Parts of Deception Island, ASPA 145–Port Foster, Deception Island, APA 150–Ardley Island, and ASPA 152–Western Bransfield Strait.

Location: ASPA 108–Green Island, ASPA 113–Litchfield Island, ASPA 140–Parts of Deception Island, ASPA 145–Port Foster, Deception Island, APA 150–Ardley Island, and ASPA 152–Western Bransfield Strait, and the Antarctic Peninsula region.

DATES: October 1, 2011 to August 31, 2013.

Nadene G. Kennedy,

Permit Officer, Office of Polar Programs.

[FR Doc. 2011–20364 Filed 8–10–11; 8:45 am]

BILLING CODE 7555–01–P

POSTAL REGULATORY COMMISSION

[Docket No. CP2011–67; Order No. 790]

New Postal Product

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is noticing a recently-filed Postal Service request to enter into an additional Global Reseller Expedited Package contract. This document invites public comments on the request and addresses several related procedural steps.

DATES: *Comments are due:* August 12, 2011.

ADDRESSES: Submit comments electronically by accessing the ''Filing Online'' link in the banner at the top of the Commission's Web site (*http://www.prc.gov*) or by directly accessing the Commission's Filing Online system at *https://www.prc.gov/prc-pages/filing-online/login.aspx.* Commenters who cannot submit their views electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section as the source for case-related information for advice on alternatives to electronic filing.

FOR FURTHER INFORMATION CONTACT: Stephen L. Sharfman, General Counsel, at 202–789–6820 (case-related information) or *DocketAdmins@prc.gov* (electronic filing assistance).

SUPPLEMENTARY INFORMATION:

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I. Introduction

On August 3, 2011, the Postal Service filed a notice announcing that it has entered into an additional Global Reseller Expedited Package (GREP) contract.[1] The Postal Service asserts that the instant contract is functionally equivalent to the GREP baseline agreement and is supported by Governors' Decision No. 10–1 attached to the Notice and originally filed in Docket No. CP2010–36. *Id.* at 1, Attachment 3. The Notice explains that Order No. 445, which established GREP Contracts 1 as a product, also authorized functionally equivalent agreements to be included within the product, provided that they meet the requirements of 39 U.S.C. 3633. *Id.* at 1–2. Additionally, the Postal Service requested to have the contract in Docket No. CP2010–36 serve as the baseline contract for future functional equivalence analyses of the GREP Contracts 1 product.

The instant contract. The Postal Service filed the instant contract pursuant to 39 CFR 3015.5. In addition, the Postal Service contends that the instant contract is in accordance with Order No. 445. The Postal Service will notify the mailer of the effective date within 30 days after all necessary regulatory approvals have been received. Notice at 3, Attachment 1 at 5. The term of the contract is one year from the effective date. It may, however, be terminated by either party on not less than 30 days' written notice. *Id.*

In support of its Notice, the Postal Service filed four attachments as follows:

- Attachment 1—a redacted copy of the contract and applicable annexes;
- Attachment 2—a redacted copy of a certified statement required by 39 CFR 3015.5(c)(2);
- Attachment 3—a redacted copy of Governors' Decision No. 10–1, which establishes prices and classifications for GREP contracts, a description of applicable GREP contracts, formulas for prices, an analysis of the formulas, and certification of the Governors' vote; and
- Attachment 4—an application for non-public treatment of materials to maintain redacted portions of the contract and supporting documents under seal.

The Notice advances reasons why the instant GREP contract fits within the Mail Classification Schedule language for GREP Contracts 1. The Postal Service states that the instant contract differs from the contract in Docket No. CP2010–36 pertaining to customer-specific information, *e.g.,* customer's name, address, representative, signatory, definition of qualifying mail, discounts offered by the reseller, minimum revenue, periodic review of minimum commitment, assignment, number of rate groups and annexes, and solicitation of reseller's customers. *Id.* at 4–6. It states that the differences, which include price variations based on updated costing information and volume commitments, do not alter the contract's functional equivalency. *Id.* at 4. The Postal Service asserts that ''[b]ecause the agreement incorporates the same cost attributes and methodology, the relevant characteristics of this GREP contract are similar, if not the same, as the relevant characteristics of the contract filed in Docket No. CP2010–36.'' *Id.*

The Postal Service concludes that its filing demonstrates that the new GREP contract complies with the requirements of 39 U.S.C. 3633 and is functionally equivalent to the baseline GREP contract. It states that the differences do not affect the services being offered or the fundamental structure of the contract. Therefore, it requests that the instant contract be included within the GREP Contracts 1 product. *Id.* at 6.

II. Notice of Filing

The Commission establishes Docket No. CP2011–67 for consideration of matters related to the contract identified in the Postal Service's Notice.

Interested persons may submit comments on whether the Postal Service's contract is consistent with the policies of 39 U.S.C. 3632, 3633, or

[1] Notice of United States Postal Service of Filing a Functionally Equivalent Global Reseller Expedited Package Negotiated Service Agreement and Application For Non-Public Treatment of Materials Filed Under Seal, August 3, 2011 (Notice).

3642. Comments are due no later than August 12, 2011. The public portions of this filing can be accessed via the Commission's Web site (*http://www.prc.gov*).

The Commission appoints Katalin K. Clendenin to serve as Public Representative in the captioned proceeding.

III. Ordering Paragraphs

It is ordered:

1. The Commission establishes Docket No. CP2011–67 for consideration of matters raised by the Postal Service's Notice.

2. Comments by interested persons in this proceeding are due no later than August 12, 2011.

3. Pursuant to 39 U.S.C. 505, Katalin K. Clendenin is appointed to serve as the officer of the Commission (Public Representative) to represent the interests of the general public in this proceeding.

4. The Secretary shall arrange for publication of this order in the **Federal Register**.

By the Commission.

Ruth Ann Abrams,

Acting Secretary.

[FR Doc. 2011–20339 Filed 8–10–11; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL REGULATORY COMMISSION

[Docket No. A2011–39; Order No. 793]

Post Office Closing

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: This document informs the public that an appeal of the closing of the Ulman, Missouri post office has been filed. It identifies preliminary steps and provides a procedural schedule. Publication of this document will allow the Postal Service, petitioners, and others to take appropriate action.

DATES: *Administrative record due (from Postal Service*): August 18, 2011; *deadline for notices to intervene:* August 30, 2011. *See* the Procedural Schedule in the **SUPPLEMENTARY INFORMATION** section for other dates of interest.

ADDRESSES: Submit comments electronically by accessing the ''Filing Online'' link in the banner at the top of the Commission's Web site (*http://www.prc.gov*) or by directly accessing the Commission's Filing Online system at *https://www.prc.gov/prc-pages/filing-online/login.aspx.* Commenters who cannot submit their views electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section as the source for case-related information for advice on alternatives to electronic filing.

FOR FURTHER INFORMATION CONTACT: Stephen L. Sharfman, General Counsel, at 202–789–6820 (case-related information) or *DocketAdmins@prc.gov* (electronic filing assistance).

SUPPLEMENTARY INFORMATION: Notice is hereby given that, pursuant to 39 U.S.C. 404(d), on August 3, 2011, the Commission received a petition for review of the Postal Service's determination to close the post office in Ulman, Missouri. The petition was filed by Buster McGowin (Petitioner) and is postmarked July 25, 2011. The Commission hereby institutes a proceeding under 39 U.S.C. 404(d)(5) and establishes Docket No. A2011–39 to consider Petitioner's appeal. If Petitioner would like to further explain his position with supplemental information or facts, Petitioner may either file a Participant Statement on PRC Form 61 or file a brief with the Commission no later than September 7, 2011.

Categories of issues apparently raised. Petitioner contends that: (1) the Postal Service failed to consider whether or not it will continue to provide a maximum degree of effective and regular postal services to the community (*see* 39 U.S.C. 404(d)(2)(A)(iii)); and (2) the Postal Service failed to adequately consider the economic savings resulting from the closure (*see* 39 U.S.C. 404(d)(2)(A)(iv)).

After the Postal Service files the administrative record and the Commission reviews it, the Commission may find that there are more legal issues than those set forth above, or that the Postal Service's determination disposes of one or more of those issues. The deadline for the Postal Service to file the applicable administrative record with the Commission is August 18, 2011. *See* 39 CFR 3001.113. In addition, the due date for any responsive pleading by the Postal Service to this notice is August 18, 2011.

Availability; Web site posting. The Commission has posted the appeal and supporting material on its Web site at *http://www.prc.gov.* Additional filings in this case and participants' submissions also will be posted on the Commission's Web site, if provided in electronic format or amenable to conversion, and not subject to a valid protective order. Information on how to use the Commission's Web site is available online or by contacting the Commission's webmaster via telephone at 202–789–6873 or via electronic mail at *prc-webmaster@prc.gov.*

The appeal and all related documents are also available for public inspection in the Commission's docket section. Docket section hours are 8 a.m. to 4:30 p.m., Monday through Friday, except on Federal government holidays. Docket section personnel may be contacted via electronic mail at *prc-dockets@prc.gov* or via telephone at 202–789–6846.

Filing of documents. All filings of documents in this case shall be made using the Internet (Filing Online) pursuant to Commission rules 9(a) and 10(a) at the Commission's Web site, *http://www.prc.gov,* unless a waiver is obtained. *See* 39 CFR 3001.9(a) and 3001.10(a). Instructions for obtaining an account to file documents online may be found on the Commission's Web site or by contacting the Commission's docket section at *prc-dockets@prc.gov* or via telephone at 202–789–6846.

The Commission reserves the right to redact personal information which may infringe on an individual's privacy rights from documents filed in this proceeding.

Intervention. Persons, other than Petitioner and respondent, wishing to be heard in this matter are directed to file a notice of intervention. *See* 39 CFR 3001.111(b). Notices of intervention in this case are to be filed on or before August 30, 2011. A notice of intervention shall be filed using the Internet (Filing Online) at the Commission's Web site unless a waiver is obtained for hardcopy filing. *See* 39 CFR 3001.9(a) and 3001.10(a).

Further procedures. By statute, the Commission is required to issue its decision within 120 days from the date it receives the appeal. *See* 39 U.S.C. 404(d)(5). A procedural schedule has been developed to accommodate this statutory deadline. In the interest of expedition, in light of the 120-day decision schedule, the Commission may request the Postal Service or other participants to submit information or memoranda of law on any appropriate issue. As required by the Commission rules, if any motions are filed, responses are due 7 days after any such motion is filed. *See* 39CFR 3001.21.

It is ordered:

1. The Postal Service shall file the applicable administrative record regarding this appeal no later than August 18, 2011.

2. Any responsive pleading by the Postal Service to this notice is due no later than August 18, 2011.

3. The procedural schedule listed below is hereby adopted.

4. Pursuant to 39 U.S.C. 505, Patricia A. Gallagher is designated officer of the

Commission (Public Representative) to represent the interests of the general public.

5. The Secretary shall arrange for publication of this notice and order in the **Federal Register**.

By the Commission.

Ruth Ann Abrams,

Acting Secretary.

PROCEDURAL SCHEDULE

August 3, 2011	Filing of Appeal.
August 18, 2011	Deadline for the Postal Service to file the applicable administrative record in this appeal.
August 18, 2011	Deadline for the Postal Service to file any responsive pleading.
August 30, 2011	Deadline for notices to intervene (*see* 39 CFR 3001.111(b)).
September 7, 2011	Deadline for Petitioner's Form 61 or initial brief in support of petition (*see* 39 CFR 3001.115(a) and (b)).
September 27, 2011	Deadline for answering brief in support of the Postal Service (*see* 39 CFR 3001.115(c)).
October 12, 2011	Deadline for reply briefs in response to answering briefs (*see* 39 CFR 3001.115(d)).
October 19, 2011	Deadline for motions by any party requesting oral argument; the Commission will schedule oral argument only when it is a necessary addition to the written filings (*see* 39 CFR 3001.116).
November 22, 2011	Expiration of the Commission's 120-day decisional schedule (*see* 39 U.S.C. 404(d)(5)).

[FR Doc. 2011–20408 Filed 8–10–11; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL REGULATORY COMMISSION

[Docket No. A2011–38; Order No. 792]

Post Office Closing

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: This document informs the public that an appeal of the closing of the Masonville, Iowa post office has been filed. It identifies preliminary steps and provides a procedural schedule. Publication of this document will allow the Postal Service, petitioners, and others to take appropriate action.

DATES: *Administrative record due (from Postal Service*): August 17, 2011; *deadline for notices to intervene:* August 30, 2011. *See* the Procedural Schedule in the **SUPPLEMENTARY INFORMATION** section for other dates of interest.

ADDRESSES: Submit comments electronically by accessing the ''Filing Online'' link in the banner at the top of the Commission's Web site (*http://www.prc.gov*) or by directly accessing the Commission's Filing Online system at *https://www.prc.gov/prc-pages/filing-online/login.aspx.* Commenters who cannot submit their views electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section as the source for case-related information for advice on alternatives to electronic filing.

FOR FURTHER INFORMATION CONTACT: Stephen L. Sharfman, General Counsel, at 202–789–6820 (case-related information) or *DocketAdmins@prc.gov* (electronic filing assistance).

SUPPLEMENTARY INFORMATION: Notice is hereby given that, pursuant to 39 U.S.C. 404(d), on August 2, 2011, the Commission received a petition for review of the Postal Service's determination to close the post office in Masonville, Iowa. The petition was filed by Nellie Marting (Petitioner) and is postmarked July 20, 2011. The Commission hereby institutes a proceeding under 39 U.S.C. 404(d)(5) and establishes Docket No. A2011–38 to consider Petitioner's appeal. If Petitioner would like to further explain her position with supplemental information or facts, Petitioner may either file a Participant Statement on PRC Form 61 or file a brief with the Commission no later than September 6, 2011.

Categories of issues apparently raised. Petitioner contends that the Postal Service failed to consider the effect of the closing on the community. *See* 39 U.S.C. 404(d)(2)(A)(i).

After the Postal Service files the administrative record and the Commission reviews it, the Commission may find that there are more legal issues than the one set forth above, or that the Postal Service's determination disposes of one or more of those issues. The deadline for the Postal Service to file the applicable administrative record with the Commission is August 17, 2011. *See* 39 CFR 3001.113. In addition, the due date for any responsive pleading by the Postal Service to this notice is August 17, 2011.

Availability; Web site posting. The Commission has posted the appeal and supporting material on its Web site at *http://www.prc.gov.* Additional filings in this case and participants' submissions also will be posted on the Commission's Web site, if provided in electronic format or amenable to conversion, and not subject to a valid protective order. Information on how to use the Commission's Web site is available online or by contacting the Commission's webmaster via telephone at 202–789–6873 or via electronic mail at *prc-webmaster@prc.gov.*

The appeal and all related documents are also available for public inspection in the Commission's docket section. Docket section hours are 8 a.m. to 4:30 p.m., Monday through Friday, except on Federal government holidays. Docket section personnel may be contacted via electronic mail at *prc-dockets@prc.gov* or via telephone at 202–789–6846.

Filing of documents. All filings of documents in this case shall be made using the Internet (Filing Online) pursuant to Commission rules 9(a) and 10(a) at the Commission's Web site, *http://www.prc.gov,* unless a waiver is obtained. *See* 39 CFR 3001.9(a) and 3001.10(a). Instructions for obtaining an account to file documents online may be found on the Commission's Web site or by contacting the Commission's docket section at *prc-dockets@prc.gov* or via telephone at 202–789–6846.

The Commission reserves the right to redact personal information which may infringe on an individual's privacy rights from documents filed in this proceeding.

Intervention. Persons, other than Petitioner and respondent, wishing to be heard in this matter are directed to file a notice of intervention. *See* 39 CFR 3001.111(b). Notices of intervention in this case are to be filed on or before August 30, 2011. A notice of intervention shall be filed using the Internet (Filing Online) at the Commission's Web site unless a waiver is obtained for hardcopy filing. *See* 39 CFR 3001.9(a) and 3001.10(a).

Further procedures. By statute, the Commission is required to issue its decision within 120 days from the date it receives the appeal. *See* 39 U.S.C. 404(d)(5). A procedural schedule has been developed to accommodate this statutory deadline. In the interest of expedition, in light of the 120-day decision schedule, the Commission may request the Postal Service or other participants to submit information or memoranda of law on any appropriate issue. As required by the Commission rules, if any motions are filed, responses are due 7 days after any such motion is filed. *See* 39 CFR 3001.21.

It is ordered:

1. The Postal Service shall file the applicable administrative record regarding this appeal no later than August 17, 2011.

2. Any responsive pleading by the Postal Service to this notice is due no later than August 17, 2011.

3. The procedural schedule listed below is hereby adopted.

4. Pursuant to 39 U.S.C. 505, Patricia A. Gallagher is designated officer of the Commission (Public Representative) to represent the interests of the general public.

5. The Secretary shall arrange for publication of this notice and order in the **Federal Register**.

By the Commission.

Ruth Ann Abrams,

Acting Secretary.

PROCEDURAL SCHEDULE

August 2, 2011	Filing of Appeal.
August 17, 2011	Deadline for the Postal Service to file the applicable administrative record in this appeal.
August 17, 2011	Deadline for the Postal Service to file any responsive pleading.
August 30, 2011	Deadline for notices to intervene (*see* 39 CFR 3001.111(b)).
September 6, 2011	Deadline for Petitioner's Form 61 or initial brief in support of petition (*see* 39 CFR 3001.115(a) and (b)).
September 26, 2011	Deadline for answering brief in support of the Postal Service (*see* 39 CFR 3001.115(c)).
October 11, 2011	Deadline for reply briefs in response to answering briefs (*see* 39 CFR 3001.115(d)).
October 18, 2011	Deadline for motions by any party requesting oral argument; the Commission will schedule oral argument only when it is a necessary addition to the written filings (*see* 39 CFR 3001.116).
November 17, 2011	Expiration of the Commission's 120-day decisional schedule (*see* 39 U.S.C. 404(d)(5)).

[FR Doc. 2011–20405 Filed 8–10–11; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL REGULATORY COMMISSION

[Docket No. A2011–40; Order No. 794]

Post Office Closing

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: This document informs the public that an appeal of the closing of the Monroe, Arkansas post office has been filed. It identifies preliminary steps and provides a procedural schedule. Publication of this document will allow the Postal Service, petitioners, and others to take appropriate action.

DATES: *Administrative record due (from Postal Service*): August 18, 2011; *deadline for notices to intervene:* August 30, 2011. *See* the Procedural Schedule in the **SUPPLEMENTARY INFORMATION** section for other dates of interest.

ADDRESSES: Submit comments electronically by accessing the ''Filing Online'' link in the banner at the top of the Commission's Web site (*http://www.prc.gov*) or by directly accessing the Commission's Filing Online system at *https://www.prc.gov/prc-pages/filing-online/login.aspx.* Commenters who cannot submit their views electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section as the source for case-related information for advice on alternatives to electronic filing.

FOR FURTHER INFORMATION CONTACT: Stephen L. Sharfman, General Counsel, at 202–789–6820 (case-related information) or *DocketAdmins@prc.gov* (electronic filing assistance).

SUPPLEMENTARY INFORMATION: Notice is hereby given that, pursuant to 39 U.S.C. 404(d), on August 3, 2011, the Commission received a petition for review of the Postal Service's determination to close the post office in Monroe, Arkansas. The petition was filed by Martha Pineda (Petitioner) and is postmarked July 26, 2011. The Commission hereby institutes a proceeding under 39 U.S.C. 404(d)(5) and establishes Docket No. A2011–40 to consider Petitioner's appeal. If Petitioner would like to further explain her position with supplemental information or facts, Petitioner may either file a Participant Statement on PRC Form 61 or file a brief with the Commission no later than September 7, 2011.

Categories of issues apparently raised. Petitioner contends that the Postal Service failed to follow the post office closure requirements. *See* 39 U.S.C. 404(d)(1).

After the Postal Service files the administrative record and the Commission reviews it, the Commission may find that there are more legal issues than the one set forth above, or that the Postal Service's determination disposes of one or more of those issues. The deadline for the Postal Service to file the applicable administrative record with the Commission is August 18, 2011. *See* 39 CFR 3001.113. In addition, the due date for any responsive pleading by the Postal Service to this notice is August 18, 2011.

Availability; Web site posting. The Commission has posted the appeal and supporting material on its Web site at *http://www.prc.gov.* Additional filings in this case and participants' submissions also will be posted on the Commission's Web site, if provided in electronic format or amenable to conversion, and not subject to a valid protective order. Information on how to use the Commission's Web site is available online or by contacting the Commission's webmaster via telephone at 202–789–6873 or via electronic mail at *prc-webmaster@prc.gov.*

The appeal and all related documents are also available for public inspection in the Commission's docket section. Docket section hours are 8 a.m. to 4:30 p.m., Monday through Friday, except on Federal government holidays. Docket section personnel may be contacted via electronic mail at *prc-dockets@prc.gov* or via telephone at 202–789–6846.

Filing of documents. All filings of documents in this case shall be made using the Internet (Filing Online) pursuant to Commission rules 9(a) and 10(a) at the Commission's Web site, *http://www.prc.gov,* unless a waiver is obtained. *See* 39 CFR 3001.9(a) and 3001.10(a). Instructions for obtaining an account to file documents online may be found on the Commission's Web site or by contacting the Commission's docket section at *prc-dockets@prc.gov* or via telephone at 202–789–6846.

The Commission reserves the right to redact personal information which may infringe on an individual's privacy rights from documents filed in this proceeding.

Intervention. Persons, other than Petitioner and respondent, wishing to be heard in this matter are directed to file a notice of intervention. *See* 39 CFR 3001.111(b). Notices of intervention in this case are to be filed on or before August 30, 2011. A notice of intervention shall be filed using the Internet (Filing Online) at the Commission's Web site unless a waiver is obtained for hardcopy filing. *See* 39 CFR 3001.9(a) and 3001.10(a).

Further procedures. By statute, the Commission is required to issue its decision within 120 days from the date it receives the appeal. *See* 39 U.S.C. 404(d)(5). A procedural schedule has been developed to accommodate this statutory deadline. In the interest of expedition, in light of the 120-day decision schedule, the Commission may request the Postal Service or other participants to submit information or memoranda of law on any appropriate issue. As required by the Commission rules, if any motions are filed, responses are due 7 days after any such motion is filed. *See* 39 CFR 3001.21.

It is ordered:

1. The Postal Service shall file the applicable administrative record regarding this appeal no later than August 18, 2011.
2. Any responsive pleading by the Postal Service to this notice is due no later than August 18, 2011.
3. The procedural schedule listed below is hereby adopted.
4. Pursuant to 39 U.S.C. 505, Emmett Rand Costich is designated officer of the Commission (Public Representative) to represent the interests of the general public.
5. The Secretary shall arrange for publication of this notice and order in the **Federal Register**.

By the Commission.

Ruth Ann Abrams,

Acting Secretary.

PROCEDURAL SCHEDULE

August 18, 2011	Deadline for the Postal Service to file the applicable administrative record in this appeal.
August 18, 2011	Deadline for the Postal Service to file any responsive pleading.
August 30, 2011	Deadline for notices to intervene (*see* 39 CFR 3001.111(b)).
September 7, 2011	Deadline for Petitioner's Form 61 or initial brief in support of petition (*see* 39 CFR 3001.115(a) and (b)).
September 27, 2011	Deadline for answering brief in support of the Postal Service (*see* 39 CFR 3001.115(c)).
October 12, 2011	Deadline for reply briefs in response to answering briefs (*see* 39 CFR 3001.115(d)).
October 19, 2011	Deadline for motions by any party requesting oral argument; the Commission will schedule oral argument only when it is a necessary addition to the written filings (*see* 39 CFR 3001.116).
November 23, 2011	Expiration of the Commission's 120-day decisional schedule (*see* 39 U.S.C. 404(d)(5)).

[FR Doc. 2011–20420 Filed 8–10–11; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL SERVICE

Board of Governors; Sunshine Act Meeting

Board Votes To Close July 25, 2011, Meeting.

By telephone vote on July 25, 2011, a majority of the members of the Board of Governors of the United States Postal Service met and voted unanimously to close to public observation its meeting held in Washington, DC, via teleconference. The Board determined that no earlier public notice was possible.

ITEMS CONSIDERED:

1. Strategic Issues.
2. Financial Matters.
3. Pricing.
4. Personnel Matters and Compensation Issues.

GENERAL COUNSEL CERTIFICATION: The General Counsel of the United States Postal Service has certified that the meeting was properly closed under the Government in the Sunshine Act.

CONTACT PERSON FOR MORE INFORMATION: Requests for information about the meeting should be addressed to the Secretary of the Board, Julie S. Moore, at (202) 268–4800.

Julie S. Moore,

Secretary.

[FR Doc. 2011–20612 Filed 8–9–11; 4:15 pm]

BILLING CODE 7710–12–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0004.

Extension:

Rule 32a–4; SEC File No. 270–473; OMB Control No. 3235–0530.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 350l *et seq.*), the Securities and Exchange Commission (''Commission'') has submitted to the Office of Management and Budget requests for extension of the previously approved collections of information discussed below.

Section 32(a)(2) of the Investment Company Act (15 U.S.C. 80a–31(a)(2)) requires that shareholders of a registered investment management or face-amount certificate company (collectively, ''funds'') ratify or reject the selection of the fund's independent public accountant. Rule 32a–4 (17 CFR 270.32a–4) exempts funds from this requirement if (i) The fund's board of directors establishes an audit committee composed solely of independent directors with responsibility for overseeing the fund's accounting and auditing processes,[1] (ii) the fund's board of directors adopts an audit committee charter setting forth the committee's structure, duties, powers and methods of operation, or sets forth such provisions in the fund's charter or bylaws,[2] and (iii) the fund maintains a copy of such an audit committee charter, and any modifications to the charter, permanently in an easily accessible place.[3]

Each fund that chooses to rely on rule 32a–4 incurs two collection of information burdens. The first, related to the board of directors' adoption of the

[1] Rule 32a–4(a).

[2] Rule 32a–4(b).

[3] Rule 32a–4(c).

audit committee charter, occurs once, when the committee is established. The second, related to the fund's maintenance and preservation of a copy of the charter in an easily accessible place, is an ongoing annual burden. The information collection requirement in rule 32a–4 enables the Commission to monitor the duties and responsibilities of an independent audit committee formed by a fund relying on the rule.

Commission staff estimates that, on average, the board of directors takes 15 minutes to adopt the audit committee charter. Commission staff has estimated that with an average of 8 directors on the board,[4] total director time to adopt the charter is 2 hours. Combined with an estimated 1 hour of paralegal time to prepare the charter for board review, the staff estimates a total one-time collection of information burden of 3 hours for each fund. Once a board adopts an audit committee charter, a fund generally maintains it in a file cabinet or as a computer file. Commission staff has estimated that there is no annual hourly burden associated with maintaining the charter in this form.[5]

Because virtually all funds extant have now adopted audit committee charters, the annual one-time collection of information burden associated with adopting audit committee charters is limited to the burden incurred by newly established funds. Commission staff estimates that fund sponsors establish approximately 117 new funds each year,[6] and that all of these funds will adopt an audit committee charter in order to rely on rule 32a–4. Thus, Commission staff estimates that the annual one-time hour burden associated with adopting an audit committee charter under rule 32a–4 going forward will be approximately 351 hours.[7]

As noted above, all funds that rely on rule 32a–4 are subject to the ongoing collection of information requirement to preserve a copy of the charter in an easily accessible place. This ongoing requirement, which Commission staff has estimated has no hourly burden, applies to all funds that have adopted an audit committee charter and continue to maintain it.

When funds adopt an audit committee charter in order to rely on rule 32a–4, they also may incur one-time costs related to hiring outside counsel to prepare the charter. Commission staff estimates that those costs average approximately $1500 per fund.[8] Commission staff understands that virtually all funds now rely on rule 32a–4 and have adopted audit committee charters, and thus estimates that the annual cost burden related to hiring outside legal counsel is limited to newly established funds.

As noted above, Commission staff estimates that approximately 117 new funds each year will adopt an audit committee charter in order to rely on rule 32a–4. Thus, Commission staff estimates that the ongoing annual cost burden associated with rule 32a–4 in the future will be approximately $175,500.[9]

The estimates of average burden hours and costs are made solely for the purposes of the Paperwork Reduction Act, and are not derived from a comprehensive or even a representative survey or study of the costs of Commission rules and forms.

The collections of information required by rule 32a–4 are necessary to obtain the benefits of the rule. The Commission is seeking OMB approval, because an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number.

The public may view the background documentation for this information collection at the following Web site, *http://www.reginfo.gov* . Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, D.C. 20503, or by sending an e-mail to: *Shagufta_Ahmed@omb.eop.gov*; and (ii) Thomas Bayer, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 6432 General Green Way, Alexandria, VA 22312 or send an e-mail to: *PRA_Mailbox@sec.gov* . Comments must be submitted to OMB within 30 days of this notice.

Dated: August 8, 2011.

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20419 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[4] This estimate is based on staff discussions with a staff representative of an entity that surveys funds and calculates fund board statistics based on responses to its surveys.

[5] No hour burden related to such maintenance of the charter was identified by the funds the Commission staff surveyed. Commission staff understands that many audit committee charters have been significantly revised after their adoption in response to the Sarbanes-Oxley Act (Pub. L. 107–204, 116 Stat. 745) and other developments. However, the costs associated with these revisions are not attributable to the requirements of rule 32a–4.

[6] This estimate is based on the number of Form N–8As filed from January 2010 through December 2010.

[7] This estimate is based on the following calculation: (3.0 burden hours for establishing charter × 117 new funds = 351 burden hours).

[8] Costs may vary based on the individual needs of each fund. However, based on the staff's conversations with outside counsel that prepare these charters, legal fees related to the preparation and adoption of an audit committee charter usually average $1500 or less. The Commission also understands that the ICI has prepared a model audit committee charter, which most legal professionals use when establishing audit committees, thereby reducing the costs associated with drafting a charter.

[9] This estimate is based on the following calculations: ($1500 cost of adopting charter × 117 newly established funds = $175,500).

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–2833.

Extension:
Rule 30b1–5; SEC File No. 270–520; OMB Control No. 3235–0577.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (the ''Commission'') has submitted to the Office of Management and Budget (''OMB'') a request for extension of the previously approved collection of information discussed below.

Rule 30b1–5 (17 CFR 270.30b1–5) under the Investment Company Act of 1940 (15 U.S.C. 80a–1 *et seq.*) (the ''Investment Company Act'') requires registered management investment companies, other than small business investment companies registered on Form N–5 (17 CFR 239.24 and 274.5) (''funds''), to file a quarterly report via the Commission's EDGAR system on Form N–Q (17 CFR 249.332 and 274.130), not more than sixty calendar days after the close of each first and third fiscal quarter, containing their complete portfolio holdings. The purpose of the collection of information required by rule 30b1–5 is to meet the disclosure requirements of the Investment Company Act and to provide investors with information necessary to evaluate an interest in the fund by improving the transparency of information about the fund's portfolio holdings.

The Commission estimates that there are 2,580 management investment companies, with a total of approximately 9,160 portfolios, that are governed by the rule. For purposes of this analysis, the burden associated with the requirements of rule 30b1–5 has been included in the collection of information requirements of Form N–Q, rather than the rule.

The collection of information under rule 30b1–5 is mandatory. The information provided under rule 30b1–5 is not kept confidential. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

The public may view the background documentation for this information collection at the following Web site, *http://www.reginfo.gov* . Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503, or by sending an e-mail to: *Shagufta_Ahmed@omb.eop.gov;* and (ii) Thomas A. Bayer, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 6432 General Green Way, Alexandria, VA 22312; or send an e-mail to: *PRA_Mailbox@sec.gov*. Comments must be submitted to OMB within 30 days of this notice.

Dated: August 8, 2011.

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20417 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0213.

Extension:

Rule 236; OMB Control No. 3235–0095; SEC File No. 270–118.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') has submitted to the Office of Management and Budget this request for extension of the previously approved collection of information discussed below.

Rule 236 (17 CFR 230.236) under the Securities Act of 1933 (''Securities Act'') (15 U.S.C. 77a *et seq.*) requires issuers relying on an exemption from the Securities Act registration requirements for the public offering of fractional shares, scrip certificates or order forms, in connection with a stock dividend, stock split, reverse stock split, conversion, merger or similar transaction, to furnish to the Commission specified information at least 10 days prior to the offering. The information is needed to provide public notice that an issuer is relying on the exemption. Public companies are the likely respondents. The information is needed to establish qualification for reliance on the exemption. The information provided by Rule 236 is required to obtain or retain benefits. All information provided to the Commission is available to the public for review upon request. Approximately 10 respondents file the information required by Rule 236 at an estimated 1.5 hours per response for a total of 15 annual burden hours (1.5 hours per response × 10 responses).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number.

The public may view the background documentation for this information collection at the following Web site, *http://www.reginfo.gov*. Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503, or by sending an e-mail to: *Shagufta_Ahmed@omb.eop.gov;* and (ii) Thomas Bayer, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 6432 General Green Way, Alexandria, VA 22312 or send an e-mail to: *PRA_Mailbox@sec.gov*. Comments must be submitted to OMB within 30 days of this notice.

Dated: August 8, 2011.

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20416 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0213.

Extension:

Rule 22d–1; SEC File No. 270–275; OMB Control No. 3235–0310.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520), the Securities and Exchange Commission (the ''Commission'') has submitted to the Office of Management and Budget requests for extension of the previously approved collection of information discussed below.

Rule 22d–1 (17 CFR 270.22d–1) under the Investment Company Act of 1940 (the ''Act'') (15 U.S.C. 80a *et seq.*) provides registered investment companies that issue redeemable securities (''funds'') an exemption from section 22(d) of the Investment Company Act (15 U.S.C. 80a–22(d)) to the extent necessary to permit scheduled variations in or elimination of the sales load on fund securities for particular classes of investors or transactions, provided certain conditions are met. The rule imposes an annual burden per series of a fund of approximately 15 minutes, so that the total annual burden for the approximately 4,862 series of funds that might rely on the rule is estimated to be 1215.5 hours.

The estimate of average burden hours is made solely for the purposes of the Paperwork Reduction Act, and is not derived from a comprehensive or even a representative survey or study.

Responses will not be kept confidential. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number.

The public may view the background documentation for this information collection at the following Web site, *http://www.reginfo.gov*. Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, D.C. 20503, or by sending an e-mail to: *Shagufta_Ahmed@omb.eop.gov;* and (ii) Thomas Bayer, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 6432 General Green Way, Alexandria, VA 22312 or send an email to: *PRA_Mailbox@sec.gov*. Comments must be submitted to OMB within 30 days of this notice.

Dated: August 8, 2011.

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20415 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Investor Education and Advocacy, Washington, DC 20549–0213.

Extension:

Regulation S–T; OMB Control No. 3235–424; SEC File No. 270–375.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') has submitted to the Office of Management and Budget this request for extension of the previously approved collection of information discussed below.

Regulation S–T (17 CFR 232.10 through 232.903) sets forth the filing requirements relating to the electronic submission of documents on the Electronic Data Gathering, Analysis and Retrieval (''EDGAR'') system. Regulation S–T is assigned one burden hour for administrative convenience because it does not directly impose any information collection requirements.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number.

The public may view the background documentation for this information collection at the following Web site, *http://www.reginfo.gov.* Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503, or by sending an e-mail to: *Shagufta_Ahmed@omb.eop.gov;* and (ii) Thomas Bayer, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 6432 General Green Way, Alexandria, VA 22312 or send an e-mail to: *PRA_Mailbox@sec.gov.* Comments must be submitted to OMB within 30 days of this notice.

Dated: August 8, 2011.

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20414 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65039; File No. SR–BX–2011–052]

Self-Regulatory Organizations; NASDAQ OMX BX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the Proprietary Traders Qualification Examination (''Series 56'')

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1], and Rule 19b–4[2] thereunder, notice is hereby given that on August 2, 2011, NASDAQ OMX BX, Inc. (''Exchange'' or ''BX'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

BX is filing with the Commission the content outline and selection specifications for the Proprietary Traders Qualification Examination (''Series 56'') program. BX will implement the proposal upon notice to its membership.

The text of the proposed rule change is available at *http://nasdaqomxbx.cchwallstreet.com,* at BX's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Recently, BX filed a proposed rule change to recognize a new category of limited representative registration for proprietary traders.[3] Specifically, BX will recognize the new registration category ''Proprietary Trader'' and the new examination, the Series 56. The new Proprietary Trader category would be limited to persons engaged solely in proprietary trading.

The Exchange has been working with the Financial Industry Regulatory Authority (''FINRA'') and certain other exchanges, many of which have recently enhanced their registration requirements to require the registration of associated persons,[4] to develop the content outline and qualification examination that would be applicable to proprietary traders. The Series 56 examination program is shared by BX and the following self-regulatory organizations (''SROs''): Boston Options Exchange; C2 Options Exchange, Incorporated; Chicago Board Options Exchange, Incorporated; Chicago Stock Exchange, Incorporated; International Securities Exchange, LLC; The NASDAQ Stock Market LLC; NASDAQ OMX PHLX LLC; National Stock Exchange, Incorporated; New York Stock Exchange, LLC; NYSE AMEX, Incorporated; and NYSE ARCA, Incorporated. Upon request by the SROs referenced above, FINRA staff convened a committee of industry representatives, BX staff and staff from the other SROs referenced above, to develop the criteria for the Series 56 examination program. This new qualification examination, the Series 56, was recently filed with the Commission.[5]

The Series 56 examination tests a candidate's knowledge of proprietary trading generally and the industry rules applicable to trading of equity securities and listed options contracts. The Series 56 examination covers, among other things, recordkeeping and recording

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* SR–BX–2011–051.

[4] *See e.g.,* Securities Exchange Act Release Nos. 63843 (February 4, 2011), 76 FR 7884 (February 11, 2011) (SR–ISE–2010–115); and 63314 (November 12, 2010), 75 FR 70957 (November 19, 2010)(SR–CBOE–2010–084).

[5] Two exchanges have thus far filed a proposed rule change respecting the Series 56, which has become effective. *See* Securities Exchange Act Release No. 64699 (June 17, 2011), 76 FR 36945 (June 23, 2011)(SR–CBOE–2011–056) and SR–NASDAQ–2011–108.

requirements, types and characteristics of securities and investments, trading practices and display execution and trading systems. While the examination is primarily dedicated to topics related to proprietary trading, the Series 56 examination also covers a few general concepts relating to customers.[6]

The qualification examination consists of 100 multiple choice questions. Candidates will have 150 minutes to complete the exam. The content outline describes the following topical sections comprising the examination: Personnel, Business Conduct and Recordkeeping and Reporting Requirements, 9 questions; Markets, Market Participants, Exchanges, and Self Regulatory Organizations, 8 questions; Types and Characteristics of Securities and Investments, 20 questions; Trading Practices and Prohibited Acts, 50 questions; and Display, Execution, and Trading Systems, 13 questions. Representatives from the applicable SROs intend to meet on a periodic basis to evaluate and, as necessary, update, the Series 56 examination program.

The Exchange understands that the other applicable SROs will also file with the Commission similar filings regarding the Series 56 examination program. The Exchange proposes to implement the Series 56 examination program upon availability in WebCRD and notification to its membership.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act[7] in general, and furthers the objectives of Section 6(c)(3)(B) of the Act,[8] pursuant to which a national securities exchange prescribes standards of training, experience and competence for members and their associated persons, in particular, by offering a new, qualification examination for proprietary traders. This filing provides the content outline and relevant specifications for the Series 56 examination program, which should help ensure that all associated persons engaged in a securities business are, and will continue to be, properly trained and qualified to perform their functions.

B. Self-Regulatory Organization's Statement on Burden on Competition

BX does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

[6] Proprietary trading firms do not have customers.

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78(c)(3)(B) [sic].

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Pursuant to Section 19(b)(3)(A) of the Act[9] and Rule 19b–4(f)(6)[10] thereunder, the Exchange has designated this proposal as one that effects a change that: (i) Does not significantly affect the protection of investors or the public interest; (ii) does not impose any significant burden on competition; and (iii) by its terms, does not become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. Rule 19b–4(f)(6)[11] requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

Under Rule 19b–4(f)(6) of the Act,[12] a proposal does not become operative for 30 days after the date of its filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. The Exchange requests that the Commission waive the 30 day operative period for this filing so that it may become effective and operative upon filing with the Commission pursuant to Section 19(b)(3)(A)[13] of the Act and subparagraph (f)(6) thereunder. The Exchange believes waiving the 30-day operative delay is consistent with the protection of investors and the public interest as the waiver will allow the Exchange to make the examination available as soon as possible to coincide with availability on another exchange.

For the reason stated above, the Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest and designates the proposal as operative upon filing.[14]

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(6).

[11] *Id.*

[12] *Id.*

[13] 15 U.S.C. 78s(b)(3)(A).

[14] For purposes only of waiving the operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f). *See also* 17 CFR 200.30–3(a)(59).

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–BX–2011–052 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BX–2011–052. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of BX. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make publicly available. All submissions should refer to File Number SR–BX–2011–052 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20356 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65042; File No. SR–BX–2011–051]

Self-Regulatory Organizations; NASDAQ OMX BX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the Proprietary Trader Examination

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that on August 2, 2011, NASDAQ OMX BX, Inc. (''Exchange'' or ''BX'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

BX is filing with the Commission a proposed rule change to amend its Rule 1032, Categories of Representative Registration, to adopt a new limited category of representative registration for proprietary traders, as described further below. BX will implement the proposal upon notice to its membership.

The text of the proposed rule change is available at *http://nasdaqomxbx.cchwallstreet.com,* at BX's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to recognize a new category of limited representative registration for proprietary traders. Currently, under BX rules, persons performing proprietary trading functions fall within the definition of representative in Rule 1011, because Rule 1011 includes persons who are engaged in the investment banking or securities business of a member. A ''Representative'' means an Associated Person [3] of a registered broker or dealer who is engaged in the investment banking or securities business for the member including the functions of supervision, solicitation or conduct of business in securities or who is engaged in the training of persons associated with a broker or dealer for any of these functions are designated as representatives. As provided in Rule 1031, all Representatives of BX members are required to be registered with the Exchange, and Representatives that are so registered are referred to as ''Registered Representatives.''

BX has been working with FINRA and certain other exchanges, many of which have recently enhanced their registration requirements to require the registration of associated persons,[4] to develop the content outline and qualification examination that would be applicable to proprietary traders. This new qualification examination, the Series 56, was recently filed with the Commission; [5] BX expects to file the content outline with the Commission as well and make it available upon availability in WebCRD. Accordingly, BX is amending its rules to recognize the new registration category ''Proprietary Trader'' and, separately, the new examination, the Series 56.

Specifically, BX proposes to adopt new subparagraph (b) to Rule 1032 to recognize the ''Proprietary Trader'' category of registration. The new Proprietary Trader category would be limited to persons performing the functions specified in new Rule 1032(b), which is proprietary trading. Persons who deal with the public do not fit in this registration category and must continue to register as General Securities Representatives. BX believes that the new limited registration category and qualification examination are appropriate, because they are tailored to proprietary trading functions. Today, these persons are required to register as a General Securities Representative and pass the Series 7 examination, which the Exchange believes covers a great deal of material that is not relevant to proprietary trading functions. Instead, the Series 56 covers both equities and options trading rules, but not all of the rules applicable to firms and persons conducting a public business. As stated above, BX will describe the Series 56 in greater detail in a separate proposed rule change.

Of course, persons registered in the new category would be subject to the continuing education requirements of Rule 1120.[6] In addition, the process for registering continues to be covered by Rule 1140, which provides that WebCRD must be used.

Today, because BX rules require it, persons associated with BX members are already registered as General Securities Representatives and have passed the Series 7 examination.[7] This proposal does not require proprietary traders who have already registered as General Securities Representatives and have passed the Series 7 examination to register under the new category as Proprietary Traders or to pass the Series 56, because BX believes this would be redundant. Persons who are registered as General Securities Representatives and have passed the Series 7 may, of course, perform the functions of a Proprietary Trader, because the new Proprietary Trader registration category is a limited registration category. This

[15] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Pursuant to Rule 1011(b), the term ''Associated Person'' means any partner, officer, director, or branch manager of a BX member or Applicant (or person occupying a similar status or performing similar functions), any person directly or indirectly controlling, controlled by, or under common control with such BX member or Applicant, or any employee of such BX member or Applicant, except that any person associated with a BX member or Applicant whose functions are solely clerical or ministerial shall not be included in the meaning of such term for purposes of the BX Equity Rules.

[4] *See e.g.,* Securities Exchange Act Release Nos. 63843 (February 4, 2011), 76 FR 7884 (February 11, 2011) (SR–ISE–2010–115); and 63314 (November 12, 2010), 75 FR 70957 (November 19, 2010)(SR–CBOE–2010–084).

[5] One exchange has thus far filed a proposed rule change respecting the Series 56 content outline, which has become effective. *See* Securities Exchange Act Release No. 64699 (June 17, 2011), 76 FR 36945 (June 23, 2011)(SR–CBOE–2011–056).

[6] *See* BX Rule 1120(a)(5).

[7] *See* BX Rule 1031.

proposal does not preclude associated persons from registering as General Securities Representatives and passing the Series 7 examination and then functioning as a Proprietary Trader.

BX expects that new members might consider the new category when applying for BX membership, once the new category and examination become available to BX members in WebCRD. Accordingly, BX believes that the new category should be helpful to attracting new members to BX, while at the same time preserving the important goals of appropriate registration and qualification for persons in the securities business. Additionally, members who hire new associated persons might choose to register those persons in the new category.

Unlike the associated persons of proprietary trading firms covered by this proposal, associated persons of firms that are NOT proprietary trading firms continue to be subject to registration as General Securities Representatives and have to pass the Series 7 examination. They are not eligible for the new registration category and examination.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [8] in general, and furthers the objectives of: (1) Section 6(c)(3)(B) of the Act,[9] pursuant to which a national securities exchange prescribes standards of training, experience and competence for members and their associated persons; and (2) Section 6(b)(5) of the Act,[10] in that it is designed, among other things, to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest, by offering a new, limited registration category to certain associated persons of BX members. The Exchange believes that these new requirements should help ensure that all associated persons engaged in a securities business are, and will continue to be, properly trained and qualified to perform their functions, because the new category and examination are limited and tailored to persons performing proprietary trading functions.

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78(c)(3)(B) [sic].

[10] 15 U.S.C. 78f(b)(5).

B. Self-Regulatory Organization's Statement on Burden on Competition

BX does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Pursuant to Section 19(b)(3)(A) of the Act [11] and Rule 19b–4(f)(6) [12] thereunder, the Exchange has designated this proposal as one that effects a change that: (i) Does not significantly affect the protection of investors or the public interest; (ii) does not impose any significant burden on competition; and (iii) by its terms, does not become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. Rule 19b–4(f)(6) [13] requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

Under Rule 19b–4(f)(6) of the Act,[14] a proposal does not become operative for 30 days after the date of its filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. The Exchange requests that the Commission waive the 30 day operative period for this filing so that it may become effective and operative upon filing with the Commission pursuant to Section 19(b)(3)(A) [15] of the Act and subparagraph (f)(6) thereunder. The Exchange believes waiving the 30-day operative delay is consistent with the protection of investors and the public interest as the waiver will allow the Exchange to make the new registration category available near the same time as other exchanges.

For the reason stated above, the Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest and designates the proposal as operative upon filing.[16]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

[11] 15 U.S.C. 78s(b)(3)(A).

[12] 17 CFR 240.19b–4(f)(6).

[13] *Id.*

[14] *Id.*

[15] 15 U.S.C. 78s(b)(3)(A).

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–BX–2011–051 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BX–2011–051. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10

[16] For purposes only of waiving the operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f). *See also* 17 CFR 200.30–3(a)(59).

a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of BX. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make publicly available. All submissions should refer to File Number SR–BX–2011–051 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[17]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20357 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65040; File No. SR–NASDAQ–2011–108]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the Proprietary Traders Qualification Examination (''Series 56'')

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that on August 1, 2011, The NASDAQ Stock Market LLC (the ''Exchange'' or ''NASDAQ'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

NASDAQ is filing with the Commission the content outline and selection specifications for the Proprietary Traders Qualification Examination (''Series 56'') program.

NASDAQ will notify its membership when the examination becomes available.

The text of the proposed rule change is available at *http:/nasdaq.cchwallstreet.com/,* at NASDAQ's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Recently, NASDAQ filed a proposed rule change to recognize a new category of limited representative registration for proprietary traders.[3] Specifically, NASDAQ will recognize the new registration category ''Proprietary Trader'' and the new examination, the Series 56. The new Proprietary Trader category would be limited to persons engaged solely in proprietary trading.

NASDAQ has been working with the Financial Industry Regulatory Authority (''FINRA'') and certain other exchanges, many of which have recently enhanced their registration requirements to require the registration of associated persons,[4] to develop the content outline and qualification examination that would be applicable to proprietary traders. The Series 56 examination program is shared by NASDAQ and the following self-regulatory organizations (''SROs''): Boston Options Exchange; C2 Options Exchange, Incorporated; Chicago Board Options Exchange, Incorporated; Chicago Stock Exchange, Incorporated; International Securities Exchange, LLC; NASDAQ OMX BX, Inc.; NASDAQ OMX PHLX LLC; National Stock Exchange, Incorporated; New York Stock Exchange, LLC; NYSE AMEX, Incorporated; and NYSE ARCA, Incorporated. Upon request by the SROs referenced above, FINRA staff convened a committee of industry representatives, NASDAQ staff and staff from the other SROs referenced above, to develop the criteria for the Series 56 examination program. This new qualification examination, the Series 56, was recently filed with the Commission.[5]

The Series 56 examination tests a candidate's knowledge of proprietary trading generally and the industry rules applicable to trading of equity securities and listed options contracts. The Series 56 examination covers, among other things, recordkeeping and recording requirements, types and characteristics of securities and investments, trading practices and display execution and trading systems. While the examination is primarily dedicated to topics related to proprietary trading, the Series 56 examination also covers a few general concepts relating to customers.[6]

The qualification examination consists of 100 multiple choice questions. Candidates will have 150 minutes to complete the exam. The content outline describes the following topical sections comprising the examination: Personnel, Business Conduct and Recordkeeping and Reporting Requirements, 9 questions; Markets, Market Participants, Exchanges, and Self Regulatory Organizations, 8 questions; Types and Characteristics of Securities and Investments, 20 questions; Trading Practices and Prohibited Acts, 50 questions; and Display, Execution, and Trading Systems, 13 questions. Representatives from the applicable SROs intend to meet on a periodic basis to evaluate and, as necessary, update, the Series 56 examination program.

NASDAQ understands that the other applicable SROs will also file with the Commission similar filings regarding the Series 56 examination program. NASDAQ proposes to implement the Series 56 examination program upon availability in WebCRD and notification to its membership.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [7] in general, and furthers the objectives of Section 6(c)(3)(B) of the Act,[8] pursuant to which a national securities exchange prescribes standards of training, experience and competence for members and their associated persons, in particular, by offering a new, qualification examination for

[17] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 64958 (July 25, 2011) (SR–NASDAQ–2011–095). *See also* SR–NASDAQ–2011–107.

[4] *See, e.g.,* Securities Exchange Act Release Nos. 63843 (February 4, 2011), 76 FR 7884 (February 11, 2011) (SR–ISE–2010–115); and 63314 (November 12, 2010), 75 FR 70957 (November 19, 2010) (SR–CBOE–2010–084).

[5] One exchange has thus far filed a proposed rule change respecting the Series 56, which has become effective. *See* Securities Exchange Act Release No. 64699 (June 17, 2011), 76 FR 36945 (June 23, 2011) (SR–CBOE–2011–056).

[6] Proprietary trading firms do not have customers.

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78(c)(3)(B) [sic].

proprietary traders. This filing provides the content outline and relevant specifications for the Series 56 examination program, which NASDAQ believes establishes the appropriate qualifications for this new registration category, because it tests the knowledge generally applicable to proprietary trading.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Pursuant to Section 19(b)(3)(A) of the Act [9] and Rule 19b–4(f)(6) [10] thereunder, the Exchange has designated this proposal as one that effects a change that: (i) Does not significantly affect the protection of investors or the public interest; (ii) does not impose any significant burden on competition; and (iii) by its terms, does not become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. Rule 19b–4(f)(6) [11] requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

Under Rule 19b–4(f)(6) of the Act,[12] a proposal does not become operative for 30 days after the date of its filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. The Exchange requests that the Commission waive the 30 day operative period for this filing so that it may become effective and operative upon filing with the Commission pursuant to Section 19(b)(3)(A) [13] of the Act and subparagraph (f)(6) thereunder. The Exchange believes waiving the 30-day operative delay is consistent with the protection of investors and the public as a waiver will make the examination available as soon as possible to coincide with availability on another exchange. For the reasons stated above, the Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest and designates the proposal as operative upon filing.[14]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–NASDAQ–2011–108 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2011–108. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of NASDAQ. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make publicly available. All submissions should refer to File Number SR–NASDAQ–2011–108 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20370 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(6).

[11] *Id.*

[12] *Id.*

[13] 15 U.S.C. 78s(b)(3)(A).

[14] For purposes only of waiving the operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f). *See also* 17 CFR 200.30–3(a)(59).

[15] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65049; File No. SR–Phlx–2011–103]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Rebates and Fees for Adding and Removing Liquidity in Select Symbols

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that, on August 1, 2011, NASDAQ OMX PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its Complex Order Fees in Section I of its Fee Schedule titled ''Rebates and Fees

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

for Adding and Removing Liquidity in Select Symbols.''

The text of the proposed rule change is available on the Exchange's Web site at *http://nasdaqtrader.com/micro.aspx?id=PHLXRulefilings,* at the principal office of the Exchange, at the Commission's Public Reference Room, and on the Commission's Web site at *http://www.sec.gov.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to amend Section I, Part B of the Exchange's Fee Schedule for Complex Orders. A Complex Order is any order involving the simultaneous purchase and/or sale of two or more different options series in the same underlying security, priced at a net debit or credit based on the relative prices of the individual components, for the same account, for the purpose of executing a particular investment strategy. Furthermore, a Complex Order can also be a stock-option order, which is an order to buy or sell a stated number of units of an underlying stock or ETF coupled with the purchase or sale of options contract(s).[3]

The Exchange proposes to increase the current Customer Rebate for Adding Liquidity with respect to Complex Orders for options overlying: (i) Standard and Poor's Depositary Receipts/SPDRs (''SPY''); [4] (ii) the PowerShares QQQ Trust (''QQQ'')®; (iii) Apple, Inc. (''AAPL''); (iv) iShares Russell 2000 Index (''IWM''); (v) Bank of America Corporation (''BAC''); (vi) Citigroup, Inc. (''C''); (vii) SPDR Gold Trust (''GLD''); (viii) Intel Corporation (''INTC''); (ix) JPMorgan Chase & Co. (''JPM''); (x) iShares Silver Trust (''SLV''); (xi) Financial Select Sector SPDR (''XLF''); and (xii) Ford Motor Company (''F'') (taken together, ''Designated Options''). The Exchange also proposes to waive the Customer Complex Order Fee for Removing Liquidity of $0.25 per contract for the following symbols: BAC, C, GLD, INTC, JPM, SLV, XLF and F. The Exchange believes that increasing the Customer Complex Order Rebate to Add Liquidity and waiving the Customer Complex Order Fee for Removing Liquidity for the symbols listed above, respectively, would attract additional Customer order flow to the Exchange.

Currently, the Exchange pays a Customer Complex Order Rebate for Adding Liquidity of $0.25 per contract in certain Select Symbols, namely SPY, QQQ, AAPL and IWM. The Exchange currently pays a Customer Complex Order Rebate for Adding Liquidity [5] of $0.24 per contract in all other Select Symbols, excluding SPY, QQQ, AAPL and IWM.[6] The Exchange also currently waives the Customer Complex Order Fee for Removing Liquidity for options overlying SPY, QQQ, AAPL and IWM.[7] The proposal would increase the Customer Rebate for Adding Liquidity to $0.26 per contract for all Designated Options.[8] In addition, the proposal would extend the current waiver of the Customer Complex Order Fee for Removing Liquidity to include the following symbols: BAC, C, GLD, INTC, JPM, SLV, XLF and F.

Under this proposal, the Exchange will pay Customer Complex Orders a Rebate for Adding Liquidity of $0.24 per contract, in any Select Symbol, except the Designated Options. The Exchange will also assess the Customer Complex Order Fee for Removing Liquidity of $0.25 per contract, in any Select Symbol, except the Designated Options.

2. Statutory Basis

The Exchange believes that its proposal to amend its Fee Schedule is consistent with Section 6(b) of the Act [9] in general, and furthers the objectives of Section 6(b)(4) of the Act [10] in particular, in that it is an equitable allocation of reasonable fees and other charges among Exchange members. The Exchange also believes that there is an equitable allocation of reasonable rebates among Exchange members.

The Exchange believes that it is reasonable and equitable to only pay a Complex Order Rebate for Adding Liquidity to Customers, as compared to other market participants, because the Customer rebate will attract Customer order flow to the Exchange for the benefit of all market participants. Likewise, the Exchange believes that it is reasonable to waive the Complex Order Fee for Removing Liquidity for Customers transacting BAC, C, GLD, INTC, JPM, SLV, XLF and F, because by waiving the fee, this also will attract Customer order flow to the Exchange which in turn also benefits all market participants.

The Exchange believes that these proposals are equitable and not unfairly discriminatory because by paying an increased Rebate for Adding Liquidity to Customers transacting Complex Orders in certain symbols and waiving Fees for Adding Liquidity to Customers transacting Complex Orders in certain additional symbols, all market participants will benefit from the increased liquidity which increased Customer order flow would bring to the Exchange.

With respect to the Customer Complex Order Rebate for Adding Liquidity the Exchange believes that it is reasonable to pay a different rebate for transacting equity options in certain symbols and with respect to the Customer Complex Order Fee for Removing Liquidity the Exchange believes that it is reasonable to assess a different Fee for Removing Liquidity in certain symbols. The Exchange currently pays a different Customer Complex Order Rebate for Adding Liquidity and assesses a different Customer Complex Order Fee for Removing Liquidity in SPY, QQQ, IWM and AAPL as compared to other Select Symbols. Trading in these Select Symbols is different from trading in other symbols in that they are more liquid, have higher volume and competition for executions is more intense. The Exchange believes the same rationale applies in paying a different Customer Complex Order Rebate for Adding Liquidity and assessing a different Customer Complex Order Fee for Removing Liquidity in BAC, C, GLD, INTC, JPM, SLV, XLF and F in that these symbols are also more liquid, have higher volume and competition for executions is more intense.

[3] *See* Exchange Rule 1080, Commentary .08(a)(i).

[4] SPY options are based on the SPDR exchange-traded fund (''ETF''), which is designed to track the performance of the S&P 500 Index.

[5] The only market participant that receives a Rebate for Adding Liquidity for Complex Orders today is a Customer.

[6] A list of all symbols subject to the Rebates and Fees for Adding and Removing Liquidity are listed in Section I of the Exchange's Fee Schedule and titled ''Select Symbols.''

[7] All other market participants are assessed a Fee for Removing Liquidity today other than Customer Complex Orders in SPY, QQQ, IWM and AAPL.

[8] This would result in a $0.01 per contract rebate increase for SPY, QQQ, IWM and AAPL and a $0.02 per contract rebate increase for BAC, C, GLD, INTC, JPM, SLV, XLF and F.

[9] 15 U.S.C. 78f(b).

[10] 15 U.S.C. 78f(b)(4).

The Exchange believes that its proposal to pay a higher rebate for transactions in equity options in the Designated Options, as compared to the other Select Symbols, is equitable and not unfairly discriminatory because the Exchange would uniformly pay the same Customer Complex Order Rebate for Adding Liquidity for all Customer Complex Orders in all Designated Options. The Exchange believes that waiving the Customer Complex Order Fee for Removing Liquidity for the following additional symbols: BAC, C, GLD, INTC, JPM, SLV, XLF and F is equitable and not unfairly discriminatory because the Exchange is uniformly waiving the Customer Complex Order Fee for Removing Liquidity.

The Exchange operates in a highly competitive market comprised of nine U.S. options exchanges in which sophisticated and knowledgeable market participants can readily send order flow to competing exchanges if they deem fee levels at a particular exchange to be excessive. The Exchange believes that the Complex Order fees and rebates it pays/assesses must be competitive with fees and rebates in place on other exchanges. The Exchange believes that this competitive marketplace impacts the fees and rebates present on the Exchange today and influences the proposals set forth above.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act.[11] At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

[11] 15 U.S.C. 78s(b)(3)(A)(ii).

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2011–103 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx-2011–103. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Phlx–2011–103 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[12]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20376 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[12] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65047; File No. SR–NYSEAmex–2011–56]

Self-Regulatory Organizations; NYSE Amex LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Amending NYSE Amex Options Rule 985NY To Permit Qualified Contingent Cross Orders To Be Electronically Submitted to the NYSE Amex System From the Floor of the Exchange for Potential Execution

August 5, 2011.

Pursuant to Section 19(b)(1)[1] of the Securities Exchange Act of 1934 (the "Act")[2] and Rule 19b–4 thereunder,[3] notice is hereby given that on August 1, 2011, NYSE Amex LLC (the "Exchange" or "NYSE Amex") filed with the Securities and Exchange Commission (the "Commission") the proposed rule change as described in Items I and II below, which Items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend NYSE Amex Options Rule 985NY to permit Qualified Contingent Cross Orders ("QCCs") to be electronically submitted to the NYSE Amex System from the Floor of the Exchange for potential [sic]. The text of the proposed rule change is available at the Exchange's Web site at *http://www.nyse.com,* on the Commission's Web site at *http://www.sec.gov,* at the Exchange's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of,

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of this filing is to amend Rule 985NY to permit QCCs to be electronically submitted to the NYSE Amex System from the Floor of the Exchange for potential execution.[4] This filing is modeled after a recently approved rule change by NASDAQ OMX PHLX (''PHLX'').[5]

Background

The Exchange recently adopted rules that permit ATP Holders to submit QCCs electronically from off the Floor through the NYSE Amex System.[6] The QCC permits an NYSE Amex ATP Holder to effect a qualified contingent trade (''QCT'') in a Regulation NMS stock and cross the options leg of the trade on the Exchange immediately upon entry and without order exposure if the order is for at least 1,000 contracts, is part of a QCT, is executed at a price at least equal to the NBBO and if there are no Customer Orders in the Exchange's Consolidated Book at the same price.[7]

The NYSE Amex Electronic QCC Filing was based on an International Securities Exchange (''ISE'') rule approved by the Commission.[8] The ISE QCC Proposal was controversial, attracting opposition from multiple exchanges including NYSE Amex.[9] The Commission, however, ultimately approved the ISE QCC Proposal, finding it to be consistent with the Securities Exchange Act of 1934 (the ''Act''). NYSE Amex implemented the NYSE Amex Electronic QCC Filing, and is proposing this rule change, as a competitive response to the approval of the PHLX floor-based QCC filing.

Under the NYSE Amex Electronic QCC Filing, QCCs currently may only be submitted electronically from off the Floor through the NYSE Amex System. In this regard, ATP Holders on the Floor of the Exchange are not allowed to enter QCCs into the NYSE Amex System, or otherwise effect them in open outcry. To provide a mechanism for the Exchange to surveil for whether QCCs were entered from off of the Floor, the Exchange adopted Commentary .01 to Rule 985NY, which requires ATP Holders to maintain books and records demonstrating that each QCC was routed to the NYSE Amex System from off of the Floor. Presently, any QCC that does not have a corresponding record required by this provision would be deemed to have been entered from on the Floor in violation of Rule 985NY. In addition, the Exchange has adopted policies and procedures to ensure that ATP Holders use the QCC properly.[10]

Discussion

QCCs permit ATP Holders to provide their customers a net price for the entire trade, and then allow the ATP Holder to execute the options leg of the trade on the Exchange at a price at least equal to the NBBO while using the QCT exemption to effect the trade in the equities leg at a price necessary to achieve the net price.

The Exchange hereby proposes to permit QCCs to be electronically entered from the Floor of the Exchange by Floor Brokers and executed immediately upon entry without exposure into the NYSE Amex System provided that no Customer Orders exist on the Exchange's Consolidated Book at the execution price, that the order is for at least 1,000 contracts,[11] and that the execution price is at or between the NBBO.[12] QCCs entered from the Floor of the Exchange would be electronically entered into the NYSE Amex System by a Floor Broker.[13] The impact of this proposal, coupled with the NYSE Amex Electronic QCC Filing, would be that ATP Holders would be able to enter QCCs both on and off of the Floor. The Exchange therefore proposes to eliminate the requirements from NYSE Amex Rule 985NY that QCCs only be submitted electronically from off the Floor to the NYSE Amex System and from Commentary .01 to NYSE Amex Rule 985NY that ATP Holders maintain books and records demonstrating that each QCC was routed to the NYSE Amex System from off of the Floor, as both will no longer be necessary if QCCs are available for entry from the Floor.

The Commission in the ISE Approval carefully considered the comparison between floor-based and electronic trading, including commissioning a

[4] The NYSE Amex System is configured to automatically reject a QCC entered when the order is for less than 1,000 contracts, is entered at a price worse than the national best bid or offer (''NBBO'') or is entered at the same price as Customer orders in the Exchange's Consolidated Book.

[5] *See* Securities Exchange Act Release No. 64688 (June 16, 2011), 76 FR 36606 (June 22, 2011) (SR–Phlx–2011–56).

[6] *See* Securities Exchange Act Release No. 64085 (March 17, 2011), 76 FR 16024 (March 22, 2011) (SR–NYSEAmex–2011–14) (''NYSE Amex Electronic QCC Filing'').

[7] A QCT is a transaction consisting of two or more component orders, executed as agent or principal, where: (a) At least one component is an NMS stock, as defined in Rule 600 of Regulation NMS under the Exchange Act; (b) all components are effected with a product or price contingency that either has been agreed to by all the respective counterparties or arranged for by a broker-dealer as principal or agent; (c) the execution of one component is contingent upon the execution of all other components at or near the same time; (d) the specific relationship between the component orders (e.g., the spread between the prices of the component orders) is determined by the time the contingent order is placed; (e) the component orders bear a derivative relationship to one another, represent different classes of shares of the same issuer, or involve the securities of participants in mergers or with intentions to merge that have been announced or cancelled; and (f) the transaction is fully hedged (without regard to any prior existing position) as a result of other components of the contingent trade. *See* Securities Exchange Act Release No. 57620 (April 4, 2008), 73 FR 19271 (April 9, 2008) (the ''QCT Release''). That release superseded a release initially granting the QCT exemption. *See* Securities Exchange Act Release No. 54389 (August 31, 2006), 71 FR 52829 (September 7, 2006) (''Original QCT Exemption'').

[8] *See* Securities Exchange Act Release No. 63955 (February 24, 2011), 76 FR 11533 (March 2, 2011) (SR–ISE–2010–73) (''ISE Approval''). *See also* Securities Exchange Act Release No. 62523 (July 16, 2010), 75 FR 43211 (July 23, 2010) (SR–ISE–2010–73) (''ISE QCC Proposal'').

[9] The Exchange notes that letters commenting on the ISE Proposal were submitted on its behalf by the Exchange's parent company, NYSE Euronext. *See e.g.,* letters dated August 9, 2010 and October 21, 2010 from Janet L. McGinness, Senior Vice President—Legal & Corporate Secretary, Legal & Government Affairs, NYSE Euronext.

[10] First, the Exchange requires ATP Holders to properly mark all QCCs as such. In addition, the Financial Industry Regulatory Authority (''FINRA''), on behalf of the Exchange, has implemented an examination and surveillance program to assess ATP Holder compliance with the requirements applicable to QCCs, including the requirement that the stock leg of the transaction be executed at or near the same time as the options leg.

[11] In order to satisfy the 1,000-contract requirement, a QCC must be for 1,000 contracts and could not be, for example, two 500-contract orders or two 500-contract legs.

[12] The Exchange does not propose to change the definition of ''Qualified Contingent Cross Order'' in NYSE Amex Rule 900.3NY. Thus, like QCCs effected pursuant to the NYSE Amex Electronic QCC Filing, QCCs entered from the Floor would need to meet the requirements of NYSE Amex Rule 900.3NY and Commentary .01 of that rule. Additionally, QCCs entered from the Floor by a Floor Broker would be entered electronically into the NYSE Amex System where a systemic check would be performed to determine whether a Customer Order is resting on the Exchange's Consolidated Book at the same price as the QCC, whether the order was for less than 1,000 contracts or whether the execution price would be outside the NBBO, each of which would cause the QCC to be rejected. If, however, the QCC is not rejected, then the NYSE Amex System would execute the QCC and simultaneously assign it an execution time.

[13] As proposed, only Floor Brokers would be permitted to enter QCCs from on the Floor and QCCs would not be permitted in open outcry.

study by the Division of Risk, Strategy and Financial Innovation (''RiskFin Study''). The RiskFin Study and the ISE Approval compare electronic trading and floor trading, the similarities between the two forms of trading, and the ability of one to replicate the other. Additionally, the Commission received comment letters from multiple floor-based exchanges that challenged the comparison that ISE drew between floor-based and electronic trading.

Despite facing direct comparisons between floor-based trading and electronic trading by multiple commenters, as well as by its own Division of RiskFin, the ISE Approval focuses on similarities between the two. The Exchange believes that the ISE Approval, on its face, draws no distinctions and identifies no material differences between floor-based and electronic trading that would confound the comparison between cross orders entered electronically and those entered on an exchange floor. The Exchange believes that its proposal to permit the entry of QCCs from the Floor is consistent with the requirements stated in the ISE Approval and consistent with the Act. The Exchange also believes that the Commission, in issuing the ISE Approval, assumed that QCC orders entered on the floor of an exchange that meet the requirements stated in the ISE Approval are equally consistent with the Act.

The Exchange has analyzed the application of Section 11(a) of the Act, and the rules thereunder, to QCCs entered from the Floor. Section 11(a) and the rules thereunder generally prohibit members of an exchange from effecting transactions on the exchange for their own account, the account of an associated person, or an account with respect to which it or an associated person thereof exercises investment discretion unless an exemption applies.[14] Section 11(a) contains multiple exemptions, including exemptions for dealers acting in the capacity of market makers, odd-lot dealers, and firms engaged in stabilizing conduct; there are also rule-based exemptions such as the ''effect vs. execute'' exception under SEC Rule 11a2–2(T) under the Act.[15]

The Exchange has in the past analyzed the application of Section 11(a) to various Exchange systems and order types.[16] The Exchange believes that the entry and execution of QCCs from the Floor raises no novel issues under Section 11(a) and the rules thereunder from a compliance, surveillance or enforcement perspective. In other words, ATP Holders on the Floor are currently required to comply and are subject to review for compliance with Section 11(a), and the rules thereunder, when using Exchange systems to effect transactions using existing order types, and they will be required to comply with Section 11(a) and the rules thereunder when entering QCCs from the Floor.

Nonetheless, out of an abundance of caution, the Exchange proposes to amend Commentary .01 to NYSE Amex Rule 985NY to prohibit Floor Brokers from entering QCCs from the Floor for their own accounts, the account of an associated person, or an account with respect to which it or an associated person thereof exercises investment discretion (each a ''prohibited account'').[17]

These restrictions set forth in Commentary .01 to NYSE Amex Rule 985NY would not limit in any way the obligation of ATP Holders, on the Floor or otherwise, to comply with Section 11(a) or the rules thereunder. For example, Floor Brokers cannot avoid or circumvent their obligations under Section 11(a) with respect to a QCC entered from the Floor by transmitting that order to another ATP Holder on the Floor or to an ATP Holder off the Floor of the Exchange. Likewise, ATP Holders off the Floor must ensure that their QCCs comply with Section 11(a) and the rules thereunder. In both cases, ATP Holders must ensure compliance with Section 11(a) and the rules thereunder, including by relying upon an exemption such as those listed above.

Additionally, to provide a mechanism for the Exchange to review whether QCCs have been entered properly by Floor Brokers, the Exchange proposes to further amend Commentary .01 to NYSE Amex Rule 985NY to require ATP Holders on the Floor to maintain books and records demonstrating that no QCC was entered from the Floor by the ATP Holder in a prohibited account. Any QCC entered from the Floor that does not have a corresponding record required by this provision would be deemed to have been entered in violation of Commentary .01 to NYSE Amex Rule 985NY.

The Exchange also proposes to amend Commentary .01 to NYSE Amex Rule 985NY to clarify that NYSE Amex Rules 934NY, 934.1NY, 934.2NY, and 934.3NY do not apply when Floor Brokers are executing QCCs. The Exchange is making this clarification to eliminate any confusion about whether the various crossing provisions in those rules may apply to QCCs when they are executed by Floor Brokers.[18] In addition, the Exchange is moving a recordkeeping obligation from current Commentary .01 to Commentary .02 and modifying it to require that with respect to QCCs routed to the NYSE Amex System from off of the Floor, ATP Holders must maintain books and records demonstrating that each such order was routed to the system from off of the Floor.[19] Finally, the Exchange is adding Commentary .03 to NYSE Amex Rule 985NY to clarify that the order exposure requirements found in NYSE Amex Rule 935NY do not apply to QCCs. That rule generally provides that with respect to orders routed to the NYSE Amex System, ATP Holders may not execute as principal orders they represent as agent unless such orders are first exposed on the Exchange for at least one second.

The Exchange's proposal addresses the mechanics of executing the stock and options components of a net-price transaction. The Exchange believes that it is necessary that it provide ATP Holders and their customers with the same trading capabilities available on other exchanges with respect to QCCs, including the change proposed herein, which would permit ATP Holders to execute the options legs of their customers' large complex orders on the Exchange.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent withSection 6(b) of the Act,[20] in general, and furthers the objectives of Section 6(b)(5)[21] and 6(b)(8) of the Act,[22] inparticular, because it is designed to promote just and equitable principles of trade,remove impediments to and perfect the mechanisms of a free and open market and a national market system and, in general, to protect investors and the public interest and does not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. The proposed rule change is consistent with the protection

[14] *See* 15 U.S.C. 78k(a).

[15] *See* 17 CFR 240.11a2–2(T).

[16] *See, e.g.* Securities Exchange Act Release No. 59472 (February 27, 2009), 74 9843 (March 6, 2009) (SR–NYSEALTR–2008–14).

[17] This restriction is the same as the one found in PHLX Rule 1064(e)(2).

[18] This change is modeled after the changes to PHLX Rule 1064(a), (b) and (c).

[19] The Exchange also is clarifying that Commentary .02 would not apply to a Qualified Contingent Cross Order covered by Commentary .01 to NYSE Amex Rule 985NY (*i.e.*, a Qualified Contingent Cross Order routed to a Floor Broker for entry into the NYSE Amex System).

[20] 15 U.S.C. 78f(b).

[21] 15 U.S.C. 78f(b)(5).

[22] 15 U.S.C. 78f(b)(8).

of investors in that it is designed to prevent Trade-Throughs. In addition, the proposed rule change would promote a free and open market by permitting the Exchange to compete with other exchanges for these types of orders. In this regard, competition would result in benefits to the investing public, whereas a lack of competition would serve to limit the choices that the public has for execution of their options business.

In addition, the proposed rule change is consistent with Section 11A(a)(1)(C) of the Act,[23] in which Congress found that it is in the public interest and appropriate for the protection of investors and the maintenance of fair and orderly markets to assure, among other things, the economically efficient execution of securities transactions. As described in detail above, the proposed rule change is also consistent with Section 11(a) of the Act and the rules thereunder.

The Exchange believes, similar to the Commission's basis for finding that ISE's QCC proposal was consistent with the Act, that permitting the entry of QCCs from the Floor ''would facilitate the execution of qualified contingent trades, for which the Commission found in the Original QCT Exemption to be of benefit to the market as a whole, contributing to the efficient functioning of the securities markets and the price discovery process.'' [24] Further, permitting the entry of QCCs from the Floor ''would provide assurance to parties to stock-option [QCTs] that their hedge would be maintained by allowing the options component to be executed as a clean cross.'' [25] In addition, like the ISE QCC Proposal, the Exchange's proposal to permit the entry of QCCs from the Floor ''is narrowly drawn and establishes a limited exception to the general principle of exposure, and retains the general principle of customer priority in the options markets.'' [26]

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act [27] and Rule 19b–4(f)(6) thereunder.[28] Because the proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative prior to 30 days from the date on which it was filed, or such shorter time as the Commission may designate, if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A) of the Act and Rule 19b–4(f)(6)(iii) thereunder.

At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–NYSEAmex–2011–56 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEAmex–2011–56. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Section, 100 F Street, NE., Washington, DC 20549–1090 on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing will also be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEAmex–2011–56 and should be submitted on or before August 31, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[29]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20388 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[23] 15 U.S.C. 78k–1(a)(1)(C).

[24] *See* ISE Approval at 11540.

[25] *Id.*

[26] *See* ISE Approval at 11541.

[27] 15 U.S.C. 78s(b)(3)(A)(iii).

[28] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has complied with this requirement.

[29] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65050; File No. SR–Phlx–2011–101]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing of Proposed Rule Change Regarding Streaming Quote Traders and Remote Streaming Quote Traders Entering Certain Option Day Limit Orders

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1], and Rule 19b–4[2] thereunder, notice is hereby given that on July 27, 2011, NASDAQ OMX PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange is filing with the Commission a proposal to allow entry of day limit orders for the proprietary accounts of Streaming Quote Traders and Remote Streaming Quote Traders.

The text of the proposed rule change is available on the Exchange's Web site at *http://nasdaqomxphlx.cchwallstreet.com/NASDAQOMXPHLX/Filings/,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposal is to amend two subsections of Exchange Rule 1080 to allow entry of day limit orders for the proprietary accounts of Streaming Quote Traders (SQTs'') and Remote Streaming Quote Traders (''RSQTs''). The proposal will promote consistency among Registered Options Traders (''ROT'') on the Exchange by allowing SQTs and RSQTs to enter day limit orders exactly as non-SQT ROTs may currently do under the rules.

Background

There are several types of market makers on the Exchange, including ROTs,[3] SQTs,[4] RSQTs,[5] and specialists.[6] Each option class and series listed on the Exchange must currently have a specialist that is either a floor-based specialist or an off-floor specialist known as a Remote Specialist. The specialist system remains un-impacted by this proposal. This proposal deals exclusively with the electronic entry of day limit orders in SQT and RSQT proprietary accounts.

Current Rule 1080 (Phlx XL and XL II) discusses the Exchange's enhanced electronic order, trading, and execution system (the ''electronic interface''). The current iteration of the Exchange's electronic interface is known as Phlx XL II.[7] Rule 1080 states that it governs the orders, execution reports and administrative order messages transmitted between the offices of member organizations and the trading floors of the Exchange. Rule 1080 also discusses what agency and proprietary orders are eligible for entry into the Exchange's electronic interface.[8]

Subsection (b)(i)(A) of Rule 1080 indicates the types of agency orders that are eligible for entry via electronic interface.[9] The Exchange does not propose any changes regarding entry of agency orders.

Subsection (b)(i)(B) of Rule 1080 indicates the types of proprietary (non-agency) orders that are eligible for entry via electronic interface. This subsection states that certain types of proprietary orders are eligible for entry via electronic interface subject to Commentary .04 of Rule 1080, discussed below.[10]

Subsection (b)(i)(B)(1) of Rule 1080 indicates the types of non-SQT ROTs and specialists proprietary orders that are eligible for entry via electronic interface, including GTC, day limit, IOC, ISO, limit on opening, and simple cancel orders.[11] The Exchange does not propose any changes regarding this subsection.[12]

Subsection (b)(i)(B)(2) states that the following types of orders for the proprietary account(s) of SQTs and RSQTs are eligible for entry via electronic interface: Limit on opening, IOC, and ISO. Currently, there is no ability for SQTs and RSQTs to enter day limit orders in their proprietary

[3] An ROT is a regular member or a foreign currency options participant of the Exchange located on the trading floor who has received permission from the Exchange to trade in options for his own account. *See* Rule 1014 (b)(i).

[4] An SQT is an ROT who has received permission from the Exchange to generate and submit option quotations electronically in options to which such SQT is assigned. An SQT may only submit such quotations while such SQT is physically present on the floor of the Exchange. *See* Rule 1014(b)(ii)(A).

[5] An RSQT is an ROT that is a member or member organization with no physical trading floor presence who has received permission from the Exchange to generate and submit option quotations electronically in options to which such RSQT has been assigned. An RSQT may only submit such quotations electronically from off the floor of the Exchange. *See* Rule 1014(b)(ii)(B).

[6] A Specialist (which includes an off-floor Remote Specialist) is an Exchange member who is registered as an options specialist pursuant to Rule 1020(a).

[7] *See* Securities Exchange Act Release No. 59995 (May 28, 2009), 74 FR 26750 (June 3, 2009) (SR–Phlx–2009–32)(order approving Phlx XL II). Phlx XL II is the Exchange's electronic order delivery and reporting system, which provides for the automatic entry and routing of Exchange-listed equity options, index options and U.S. dollar-settled foreign currency options orders to the Exchange trading floor. Rule 1080(a).

[8] In addition, Rule 1080 deals with, among other things, how quotations interact with limit orders on the book, order routing through the electronic interface, Price Improvement XL (known as ''PIXL''), specialized quote feed (known as ''SQF''), qualified contingent cross orders, and complex orders.

[9] Rule 1080(b)(i)(A). This section states that for purposes of Exchange options trading, an agency order is any order entered on behalf of a public customer, and does not include any order entered for the account of a broker-dealer, or any account in which a broker-dealer or an associated person of a broker-dealer has any direct or indirect interest.

[10] Commentary .04 of Rule 1080 states that Orders for the proprietary accounts of SQTs, RSQTs and non-SQT ROTs that may be entered for delivery through the electronic interface (through the use of Exchange approved proprietary systems to interface with the electronic interface of the Exchange) shall be for a minimum of one (1) contract. Orders for the proprietary account(s) of non-SQT ROTs with a size of less than 10 contracts shall be submitted as IOC only. Orders for the proprietary account(s) of SQTs and RSQTs shall be submitted as IOC only.

[11] Rule 1066 discusses certain order types.

[12] Subsection (b)(i)(B)(1), states that the following types of orders for the proprietary account(s) of non-SQT ROTs and specialists with a size of 10 contracts or greater are eligible for entry via electronic interface with AUTOM: GTC, day limit, IOC, ISO, limit on opening and simple cancel. The subsection states also that orders for the proprietary account(s) of non-SQT ROTs and specialists with a size of less than 10 contracts shall be submitted as IOC only.

accounts. The proposal corrects this limitation by allowing day limit orders for the proprietary account(s) of SQTs and RSQTs to be entered pursuant to subsection (b)(i)(B)(2). The proposed change will promote consistency among ROTs by allowing SQTs and RSQTs to do what Commentary .04 of Rule 1080 now allows non-SQT ROTs to do: enter certain day limit orders (10 or more contracts) in their proprietary accounts.[13]

Commentary .04 of Rule 1080 states that orders for the proprietary accounts of SQTs, RSQTs and non-SQT ROTs may be entered for delivery via electronic interface through the use of Exchange approved proprietary systems of members that interface with the Exchange's electronic interface.[14] Currently, proprietary non-SQT ROT orders with a size of less than 10 contracts have to be submitted as IOC and larger orders may be submitted as day limit and other order types; while proprietary SQT and RSQT orders may only be submitted as IOC.

The Exchange is proposing to put all the ROTs (SQTs, RSQTs and non-SQT ROTs) on an equal footing. Specifically, the Exchange proposes to state in Commentary .04 that orders for the proprietary account(s) of SQTs, RSQTs, and non-SQT ROTs with a size of less than 10 contracts shall be submitted as IOC only. Thus, where SQT and RSQT orders under the current rule could only be submitted as IOC, the proposed change to Commentary .04 would allow these SQTs and RSQTs to enter non IOC orders (e.g. day orders) in proprietary accounts if they are for 10 or more contracts.

The Exchange is proposing to amend subsection (b)(i)(B)(2) and Commentary.04 of Exchange Rule 1080 in order to encourage more liquidity by allowing market makers to rest more orders on the book. Initially with the onset of electronic quoting, the Exchange wanted to encourage electronic quoting and trading and thus did not accept day or day limit orders in the proprietary accounts of liquidity providers such as RSQTs and SQTs nor allow SQTs and RSQTs to submit non-IOC orders. With the extensive development of electronic market making, however, the Exchange has come to believe that allowance of day orders per subsection (b)(i)(B)(2) and Commentary .04 would enhance liquidity rather than discourage electronic quoting and trading on the Exchange, to the benefit of traders and public customers.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act[15] in general, and furthers the objectives of Section 6(b)(5) of the Act[16] in particular, in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, and to remove impediments to and perfect the mechanisms of a free and open market and a national market system by further enhancing liquidity to the benefit of traders and public customers. This would be achieved by conforming subsection (b)(i)(B)(2) and Commentary .04 of Rule 1080 and thereby promoting consistency through uniformly allowing day limit orders for the proprietary account(s) of Registered Options Traders (SQTs, RSQTs, and non-SQT ROTs) to be entered via the Exchange's electronic interface. Prior to this proposal, such orders were allowed only for non-SQT ROTs.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the Exchange consents, the Commission shall: (a) By order approve or disapprove such proposed rule change, or (b) institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–Phlx–2011–101 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2011–101. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Phlx–2011–101 and should be submitted on or before September 1, 2011.

[13] Also, subsection (b)(i)(B)(1) allows non-SQTs and specialists to enter certain day limit orders (10 or more contracts) in their proprietary accounts.

[14] Such orders have to be for a minimum of one (1) contract.

[15] 15 U.S.C. 78f(b).

[16] 15 U.S.C. 78f(b)(5).

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[17]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20390 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65048; File No. SR–NYSEArca–2011–52]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Amending NYSE Arca Options Rule 6.90 To Permit Qualified Contingent Cross Orders To Be Electronically Submitted to the NYSE Arca System From the Floor of the Exchange for Potential Execution

August 5, 2011.

Pursuant to Section 19(b)(1)[1] of the Securities Exchange Act of 1934 (the ''Act'')[2] and Rule 19b–4 thereunder,[3] notice is hereby given that on August 1, 2011, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend NYSE Arca Options Rule 6.90 to permit Qualified Contingent Cross Orders (''QCCs'') to be electronically submitted to the NYSE Arca System from the Floor of the Exchange for potential execution.

The text of the proposed rule change is available at the Exchange's Web site at *http://www.nyse.com,* on the Commission's Web site at *http://www.sec.gov,* at the Exchange's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of this filing is to amend Rule 6.90 to permit QCCs to be electronically submitted to the NYSE Arca System from the Floor of the Exchange for potential execution.[4] This filing is modeled after a recently approved rule change by NASDAQ OMX PHLX (''PHLX'').[5]

Background

The Exchange recently adopted rules that permit OTP Holders to submit QCCs electronically from off the Floor through the NYSE Arca System.[6] The QCC permits an NYSE Arca OTP Holder to effect a qualified contingent trade (''QCT'') in a Regulation NMS stock and cross the options leg of the trade on the Exchange immediately upon entry and without order exposure if the order is for at least 1,000 contracts, is part of a QCT, is executed at a price at least equal to the NBBO and if there are no Customer Orders in the Exchange's Consolidated Book at the same price.[7]

The NYSE Arca Electronic QCC Filing was based on an International Securities Exchange (''ISE'') rule approved by the Commission.[8] The ISE QCC Proposal was controversial, attracting opposition from multiple exchanges including NYSE Arca.[9] The Commission, however, ultimately approved the ISE QCC Proposal, finding it to be consistent with the Securities Exchange Act of 1934 (the ''Act''). NYSE Arca implemented the NYSE Arca Electronic QCC Filing, and is proposing this rule change, as a competitive response to the approval of the PHLX floor-based QCC filing.

Under the NYSE Arca Electronic QCC Filing, QCCs currently may only be submitted electronically from off the Floor through the NYSE Arca System. In this regard, OTP Holders on the Floor of the Exchange are not allowed to enter QCCs into the NYSE Arca System, or otherwise effect them in open outcry. To provide a mechanism for the Exchange to surveil for whether QCCs were entered from off of the Floor, the Exchange adopted Commentary .01 to Rule 6.90, which requires OTP Holders to maintain books and records demonstrating that each QCC was routed to the NYSE Arca System from off of the Floor. Presently, any QCC that does not have a corresponding record required by this provision would be deemed to have been entered from on the Floor in violation of Rule 6.90. In addition, the Exchange has adopted policies and procedures to ensure that OTP Holders use the QCC properly.[10]

Discussion

QCCs permit OTP Holders to provide their customers a net price for the entire

[17] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C.78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

[4] The NYSE Arca System is configured to automatically reject a QCC entered when the order is for less than 1,000 contracts, is entered at a price worse than the national best bid or offer (''NBBO'') or is entered at the same price as Customer orders in the Exchange's Consolidated Book.

[5] *See* Securities Exchange Act Release No. 64688 (June 16, 2011), 76 FR 36606 (June 22, 2011) (SR–Phlx–2011–56).

[6] *See* Securities Exchange Act Release No. 64086 (March 17, 2011), 76 FR 16021 (March 22, 2011) (SR–NYSEArca–2011–09) (''NYSE Arca Electronic QCC Filing'').

[7] A QCT is a transaction consisting of two or more component orders, executed as agent or principal, where: (a) At least one component is an NMS stock, as defined in Rule 600 of Regulation NMS under the Exchange Act; (b) all components are effected with a product or price contingency that either has been agreed to by all the respective counterparties or arranged for by a broker-dealer as principal or agent; (c) the execution of one component is contingent upon the execution of all other components at or near the same time; (d) the specific relationship between the component orders (e.g., the spread between the prices of the component orders) is determined by the time the contingent order is placed; (e) the component orders bear a derivative relationship to one another, represent different classes of shares of the same issuer, or involve the securities of participants in mergers or with intentions to merge that have been announced or cancelled; and (f) the transaction is fully hedged (without regard to any prior existing position) as a result of other components of the contingent trade. *See* Securities Exchange Act Release No. 57620 (April 4, 2008), 73 FR 19271 (April 9, 2008) (the ''QCT Release''). That release superseded a release initially granting the QCT exemption. *See* Securities Exchange Act Release No. 54389 (August 31, 2006), 71 FR 52829 (September 7, 2006) (''Original QCT Exemption'').

[8] *See* Securities Exchange Act Release No. 63955 (February 24, 2011), 76 FR 11533 (March 2, 2011) (SR–ISE–2010–73) (''ISE Approval''). *See also* Securities Exchange Act Release No. 62523 (July 16, 2010), 75 FR 43211 (July 23, 2010) (SR–ISE–2010–73) (''ISE QCC Proposal'').

[9] The Exchange notes that letters commenting on the ISE Proposal were submitted on its behalf by the Exchange's parent company, NYSE Euronext. *See e.g.,* letters dated August 9, 2010 and October 21, 2010 from Janet L. McGinness, Senior Vice President—Legal & Corporate Secretary, Legal & Government Affairs, NYSE Euronext.

[10] First, the Exchange requires OTP Holders to properly mark all QCCs as such. In addition, the Financial Industry Regulatory Authority (''FINRA''), on behalf of the Exchange, has implemented an examination and surveillance program to assess OTP Holder compliance with the requirements applicable to QCCs, including the requirement that the stock leg of the transaction be executed at or near the same time as the options leg.

trade, and then allow the OTP Holder to execute the options leg of the trade on the Exchange at a price at least equal to the NBBO while using the QCT exemption to effect the trade in the equities leg at a price necessary to achieve the net price.

The Exchange hereby proposes to permit QCCs to be electronically entered from the Floor of the Exchange by Floor Brokers and executed immediately upon entry without exposure into the NYSE Arca System provided that no Customer Orders exist on the Exchange's Consolidated Book at the execution price, that the order is for at least 1,000 contracts,[11] and that the execution price is at or between the NBBO.[12] QCCs entered from the Floor of the Exchange would be electronically entered into the NYSE Arca System by a Floor Broker.[13] The impact of this proposal, coupled with the NYSE Arca Electronic QCC Filing, would be that OTP Holders would be able to enter QCCs both on and off of the Floor. The Exchange therefore proposes to eliminate the requirements from NYSE Arca Rule 6.90 that QCCs only be submitted electronically from off the Floor to the NYSE Arca System and from Commentary .01 to NYSE Arca Rule 6.90 that OTP Holders maintain books and records demonstrating that each QCC was routed to the NYSE Arca System from off of the Floor, as both will no longer be necessary if QCCs are available for entry from the Floor.

The Commission in the ISE Approval carefully considered the comparison between floor-based and electronic trading, including commissioning a study by the Division of Risk, Strategy and Financial Innovation (''RiskFin Study''). The RiskFin Study and the ISE Approval compare electronic trading and floor trading, the similarities between the two forms of trading, and the ability of one to replicate the other. Additionally, the Commission received comment letters from multiple floor-based exchanges that challenged the comparison that ISE drew between floor-based and electronic trading.

Despite facing direct comparisons between floor-based trading and electronic trading by multiple commenters, as well as by its own Division of RiskFin, the ISE Approval focuses on similarities between the two. The Exchange believes that the ISE Approval, on its face, draws no distinctions and identifies no material differences between floor-based and electronic trading that would confound the comparison between cross orders entered electronically and those entered on an exchange floor. The Exchange believes that its proposal to permit the entry of QCCs from the Floor is consistent with the requirements stated in the ISE Approval and consistent with the Act. The Exchange also believes that the Commission, in issuing the ISE Approval, assumed that QCC orders entered on the floor of an exchange that meet the requirements stated in the ISE Approval are equally consistent with the Act.

The Exchange has analyzed the application of Section 11(a) of the Act, and the rules thereunder, to QCCs entered from the Floor. Section 11(a) and the rules thereunder generally prohibit members of an exchange from effecting transactions on the exchange for their own account, the account of an associated person, or an account with respect to which it or an associated person thereof exercises investment discretion unless an exemption applies.[14] Section 11(a) contains multiple exemptions, including exemptions for dealers acting in the capacity of market makers, odd-lot dealers, and firms engaged in stabilizing conduct; there are also rule-based exemptions such as the ''effect vs. execute'' exception under SEC Rule 11a2–2(T) under the Act.[15]

The Exchange has in the past analyzed the application of Section 11(a) to various Exchange systems and order types.[16] The Exchange believes that the entry and execution of QCCs from the Floor raises no novel issues under Section 11(a) and the rules thereunder from a compliance, surveillance or enforcement perspective. In other words, OTP Holders on the Floor are currently required to comply and are subject to review for compliance with Section 11(a), and the rules thereunder, when using Exchange systems to effect transactions using existing order types, and they will be required to comply with Section 11(a) and the rules thereunder when entering QCCs from the Floor.

Nonetheless, out of an abundance of caution, the Exchange proposes to amend Commentary .01 to NYSE Arca Rule 6.90 to prohibit Floor Brokers from entering QCCs from the Floor for their own accounts, the account of an associated person, or an account with respect to which it or an associated person thereof exercises investment discretion (each a ''prohibited account'').[17]

These restrictions set forth in Commentary .01 to NYSE Arca Rule 6.90 would not limit in any way the obligation of OTP Holders, on the Floor or otherwise, to comply with Section 11(a) or the rules thereunder. For example, Floor Brokers cannot avoid or circumvent their obligations under Section 11(a) with respect to a QCC entered from the Floor by transmitting that order to another OTP Holder on the Floor or to an OTP Holder off the Floor of the Exchange. Likewise, OTP Holders off the Floor must ensure that their QCCs comply with Section 11(a) and the rules thereunder. In both cases, OTP Holders must ensure compliance with Section 11(a) and the rules thereunder, including by relying upon an exemption such as those listed above.

Additionally, to provide a mechanism for the Exchange to review whether QCCs have been entered properly by Floor Brokers, the Exchange proposes to further amend Commentary .01 to NYSE Arca Rule 6.90 to require OTP Holders on the Floor to maintain books and records demonstrating that no QCC was entered from the Floor by the OTP Holder in a prohibited account. Any QCC entered from the Floor that does not have a corresponding record required by this provision would be deemed to have been entered in violation of Commentary .01 to NYSE Arca Rule 6.90.

The Exchange also proposes to amend Commentary .01 to NYSE Arca Rule 6.90 to clarify that NYSE Arca Rule 6.47 does not apply when Floor Brokers are executing QCCs. The Exchange is making this clarification to eliminate any confusion about whether the various crossing provisions in Rule 6.47 may apply to QCCs when they are

[11] In order to satisfy the 1,000-contract requirement, a QCC must be for 1,000 contracts and could not be, for example, two 500-contract orders or two 500-contract legs.

[12] The Exchange does not propose to change the definition of ''Qualified Contingent Cross Order'' in NYSE Arca Rule 6.62. Thus, like QCCs effected pursuant to the NYSE Arca Electronic QCC Filing, QCCs entered from the Floor would need to meet the requirements of NYSE Arca Rule 6.62 and Commentary .02 of that rule. Additionally, QCCs entered from the Floor by a Floor Broker would be entered electronically into the NYSE Arca System where a systemic check would be performed to determine whether a Customer Order is resting on the Exchange's Consolidated Book at the same price as the QCC, whether the order was for less than 1,000 contracts or whether the execution price would be outside the NBBO, each of which would cause the QCC to be rejected. If, however, the QCC is not rejected, then the NYSE Arca System would execute the QCC and simultaneously assign it an execution time.

[13] As proposed, only Floor Brokers would be permitted to enter QCCs from on the Floor and QCCs would not be permitted in open outcry.

[14] *See* 15 U.S.C. 78k(a).

[15] *See* 17 CFR 240.11a2–2(T).

[16] *See, e.g.* Securities Exchange Act Release No. 54238 (July 28, 2006), 71 FR 44758 (August 7, 2006) (SR–NYSEArca–2006–13).

[17] This restriction is the same as the one found in PHLX Rule 1064(e)(2).

executed by Floor Brokers.[18] In addition, the Exchange is moving a recordkeeping obligation from current Commentary .01 to Commentary 02 and modifying it to require that with respect to QCCs routed to the NYSE Arca System from off of the Floor, OTP Holders must maintain books and records demonstrating that each such order was routed to the system from off of the Floor.[19] Finally, the Exchange is adding Commentary .03 to NYSE Arca Rule 6.90 to clarify that the order exposure requirements found in NYSE Arca Rule 6.47A do not apply to QCCs. That rule generally provides that with respect to orders routed to the NYSE Arca System, OTP Holders may not execute as principal orders they represent as agent unless such orders are first exposed on the Exchange for at least one second.

The Exchange's proposal addresses the mechanics of executing the stock and options components of a net-price transaction. The Exchange believes that it is necessary that it provide OTP Holders and their customers with the same trading capabilities available on other exchanges with respect to QCCs, including the change proposed herein, which would permit OTP Holders to execute the options legs of their customers' large complex orders on the Exchange.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with Section 6(b) of the Act,[20] in general, and furthers the objectives of Section 6(b)(5) [21] and 6(b)(8) of the Act,[22] in particular, because it is designed to promote just and equitable principles of trade, remove impediments to and perfect the mechanisms of a free and open market and a national market system and, in general, to protect investors and the public interest and does not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. The proposed rule change is consistent with the protection of investors in that it is designed to prevent Trade-Throughs. In addition, the proposed rule change would promote a free and open market by permitting the Exchange to compete with other exchanges for these types of orders. In this regard, competition would result in benefits to the investing public, whereas a lack of competition would serve to limit the choices that the public has for execution of their options business.

In addition, the proposed rule change is consistent with Section 11A(a)(1)(C) of the Act,[23] in which Congress found that it is in the public interest and appropriate for the protection of investors and the maintenance of fair and orderly markets to assure, among other things, the economically efficient execution of securities transactions. As described in detail above, the proposed rule change is also consistent with Section 11(a) of the Act and the rules thereunder.

The Exchange believes, similar to the Commission's basis for finding that ISE's QCC proposal was consistent with the Act, that permitting the entry of QCCs from the Floor ''would facilitate the execution of qualified contingent trades, for which the Commission found in the Original QCT Exemption to be of benefit to the market as a whole, contributing to the efficient functioning of the securities markets and the price discovery process.'' [24] Further, permitting the entry of QCCs from the Floor ''would provide assurance to parties to stock-option [QCTs] that their hedge would be maintained by allowing the options component to be executed as a clean cross.'' [25] In addition, like the ISE QCC Proposal, the Exchange's proposal to permit the entry of QCCs from the Floor ''is narrowly drawn and establishes a limited exception to the general principle of exposure, and retains the general principle of customer priority in the options markets.'' [26]

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act [27] and Rule 19b–4(f)(6) thereunder.[28] Because the proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative prior to 30 days from the date on which it was filed, or such shorter time as the Commission may designate, if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A) of the Act and Rule 19b–4(f)(6)(iii) thereunder.

At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2011–52 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2011–52. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your

[18] This change is modeled after the changes to PHLX Rule 1064(a), (b) and (c).

[19] The Exchange also is clarifying that Commentary .02 would not apply to a Qualified Contingent Cross Order covered by Commentary .01 to NYSE Arca Rule 6.90 (*i.e.,* a Qualified Contingent Cross Order routed to a Floor Broker for entry into the NYSE Arca System).

[20] 15 U.S.C. 78f(b).

[21] 15 U.S.C. 78f(b)(5).

[22] 15 U.S.C. 78f(b)(8).

[23] 15 U.S.C. 78k–1(a)(1)(C).

[24] *See* ISE Approval at 11540.

[25] *Id.*

[26] *See* ISE Approval at 11541.

[27] 15 U.S.C. 78s(b)(3)(A)(iii).

[28] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has complied with this requirement.

comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (http://www.sec.gov/rules/sro.shtml). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Section, 100 F Street, NE., Washington, DC 20549–1090 on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing will also be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca–2011–52 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[29]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20389 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[29] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65046; File No. SR–Phlx–2011–105]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the Active SQF Port Fee

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on August 2, 2011, NASDAQ OMX PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the Exchange's Fee Schedule to extend the Active Specialized Quote Feed (''SQF'') Port Fee monthly cap from its current expiration of November 30, 2011[3] to December 30, 2011.

The text of the proposed rule change is available on the Exchange's Web site at *http://nasdaqtrader.com/micro.aspx?id=PHLXfilings,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to extend the timeframe for member organizations to cap their Active SQF Port Fees in order that they will have additional time to transition from SQF 5.0 to SQF 6.0.[4] Active SQF ports refer to ports that receive inbound quotes at any time within that month. SQF is an interface that enables specialists, Streaming Quote Traders (''SQTs'') and Remote Streaming Quote Traders (''RSQTs'') to connect and send quotes into Phlx XL.

The Exchange currently has a tiered Active SQF Port Fee as follows:

Number of Active SQF Ports	Cost Per Port Per Month
0–4	350
5–18	1,250
19–40	2,350
41 and over	3,000

Active SQF Port Fees are capped at $500 per month for member organizations that are (i) Phlx Only Members;[5] and (ii) have 50 or less SQT assignments affiliated with their member organization. Currently, Active SQF Port Fees are capped at $40,000 per month (''Cap'') until November 30, 2011 for all member organizations other than those member organizations who meet the requirements of the $500 per month cap. The purpose of the Cap is to ensure member organizations are not assessed fees in excess of the Active SQF Port Fees.

The Exchange proposes to extend the Cap until December 30, 2011 because the Exchange believes that member organizations would require additional time to properly transition to SQF 6.0 ports. On January 2, 2012, there will no longer be a Cap in effect for the Active SQF Port Fee. No other changes are proposed with respect to Active SQF Port Fees.

2. Statutory Basis

The Exchange believes that its proposal to amend its Fee Schedule is consistent with Section 6(b) of the Act[6] in general, and furthers the objectives of Section 6(b)(4) of the Act[7] in particular, in that it is an equitable allocation of reasonable fees and other charges among

[3] *See* Securities Exchange Act Release No. 63780 (January 26, 2011), 76 FR 5846 (February 2, 2011) (SR–Phlx–2011–07).

[4] The Exchange released SQF 6.0 on October 11, 2010. The Exchange anticipates that member organizations will utilize both SQF 5.0 and SQF 6.0 for a period of time. SQF 6.0 will increase efficiency for interested participants by allowing them to access in a single feed available to all participants, rather than through accessing multiple feeds, information such as execution reports and other relevant data. In order for participants to access all of this information currently or for any that do not use SQF 6.0 in the future, they must rely on a risk management feed and the TOPO/TOPO Plus Orders Exchange interfaces. Non quoting firms that would like to receive the relevant information available over SQF will be allowed to connect to the SQF interface, but not send quotes. Data proposed for SQF 6.0 will initially include the following: (1) Options Auction Notifications (*e.g.,* opening imbalance, market exhaust, PIXL or other information currently provided on SQF 5.0); (2) Options Symbol Directory Messages (currently provided on SQF 5.0); (3) System Event Messages (*e.g.,* start of messages, start of system hours, start of quoting, start of opening); (4) Complex Order Strategy Auction Notifications (COLA); (5) Complex Order Strategy messages; (6) Option Trading Action Messages (*e.g.,* halts, resumes); and (7) Complex Strategy Trading Action Message (*e.g.,* halts, resumes). *See* Securities Exchange Act Release No. 63034 (October 4, 2010), 75 FR 62441 (October 8, 2010) (SR–Phlx–2010–124).

[5] For purposes of the Active SQF Port Fee, a Phlx Only Member is a Phlx member that is not a member or member organization of another national securities exchange.

[6] 15 U.S.C. 78f(b).

[7] 15 U.S.C. 78f(b)(4).

Exchange members and other persons using its facilities.

The Exchange believes that its proposal to extend the applicability of the Cap for Active SQF Port Fees is both reasonable and equitable because it would allow member organizations additional time to transition from SQF 5.0 to SQF 6.0. The proposal is equitable and not unfairly discriminatory in that the Exchange is extending the Cap for all member organizations.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act.[8] At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2011–105 on the subject line.

[8] 15 U.S.C. 78s(b)(3)(A)(ii).

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2011–105. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Phlx–2011–105 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[9]

Elizabeth M. Murphy,

Secretary.

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BILLING CODE 8011–01–P

[9] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65041; File No. SR–NASDAQ–2011–107]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Correct the Proprietary Trader Registration Category

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that on August 1, 2011, The NASDAQ Stock Market LLC (the ''Exchange'' or ''NASDAQ'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

NASDAQ is filing with the Commission a proposed rule change to correct a prior filing to make it applicable to NASDAQ and not just the NASDAQ Options Market (''NOM'').[3] The prior filing amended NASDAQ Rule 1032, Categories of Representative Registration, to adopt a new limited category of representative registration for proprietary traders, as described further below.

The text of the proposed rule change is available at *http:/nasdaq.cchwallstreet.com/,* at NASDAQ's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 64958 (July 25, 2011) (SR–NASDAQ–2011– 095) (''NASDAQ Proprietary Trader Filing'').

the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to correct a prior filing, the NASDAQ Proprietary Trader Filing, to make it applicable to NASDAQ and not just the NASDAQ Options Market (''NOM''). Although that filing was correctly submitted as a NASDAQ filing, the exhibit to the filing was incorrectly limited to NOM.

The NASDAQ Proprietary Trader Filing amended NASDAQ Rule 1032, Categories of Representative Registration, to adopt a new limited category of representative registration for proprietary traders. This new category should apply to all NASDAQ members, not just NOM participants. Specifically, paragraph (c) to Rule 1032 recognized the ''Proprietary Trader'' category of registration for persons engaged solely in proprietary trading; it expressly provides that such person's activities in the investment banking or securities business are limited solely to proprietary trading, that he passes the Series 56 and that he is an associated person of a proprietary trading firm as defined in Rule 1011(o).[4] NASDAQ proposes herein that Rule 1032(c) applies to all NASDAQ members.

Accordingly, as stated in the NASDAQ Proprietary Trader Filing, associated persons of NASDAQ members who deal with the public do not fit in this registration category and must continue to register as General Securities Representatives, and NASDAQ believes that the new limited registration category and qualification examination are appropriate, because they are tailored to proprietary trading functions. In addition, because NASDAQ rules require it, persons associated with NASDAQ members are, today, already registered as General Securities Representatives and have passed the Series 7 examination. As applied to all NASDAQ members, this proposal does not require proprietary traders who have already registered as General Securities Representatives and have passed the Series 7 examination to register under the new category as Proprietary Traders or to pass the Series 56, because NASDAQ believes this would be redundant. Persons who are registered as General Securities Representatives and have passed the Series 7 may, of course, perform the functions of a Proprietary Trader, because the new Proprietary Trader registration category is a limited registration category. As applied to all NASDAQ members, this proposal does not preclude associated persons from registering as General Securities Representatives and passing the Series 7 examination and then functioning as a Proprietary Trader.

NASDAQ expects that new members might consider the new category when applying for NASDAQ membership, once the new category and examination become available to NASDAQ members in WebCRD. Accordingly, NASDAQ believes that the new category should be helpful to attracting new members to NASDAQ, while at the same time preserving the important goals of appropriate registration and qualification for persons in the securities business. Additionally, members who hire new associated persons might choose to register those persons in the new category.

Unlike the associated persons of proprietary trading firms covered by this proposal, associated persons of NASDAQ members that are NOT proprietary trading firms continue to be subject to registration as General Securities Representatives and have to pass the Series 7 examination.[5] They are not eligible for the new registration category and examination.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act[6] in general, and furthers the objectives of: (1) Section 6(c)(3)(B) of the Act,[7] pursuant to which a national securities exchange prescribes standards of training, experience and competence for members and their associated persons; and (2) Section 6(b)(5) of the Act,[8] in that it is designed, among other things, to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest, by offering a new, limited registration category to NASDAQ members. The Exchange believes that these new requirements should help ensure that all associated persons engaged in a securities business are, and will continue to be, properly trained and qualified to perform their functions, because the new category and examination are limited and tailored to persons performing proprietary trading functions. This proposal corrects the NASDAQ Proprietary Trader Filing by applying Rule 1032(c) to all NASDAQ members, not just NOM participants.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Pursuant to Section 19(b)(3)(A) of the Act[9] and Rule 19b–4(f)(6)[10] thereunder, the Exchange has designated this proposal as one that effects a change that: (i) Does not significantly affect the protection of investors or the public interest; (ii) does not impose any significant burden on competition; and (iii) by its terms, does not become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. Rule 19b–4(f)(6)[11] requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[4] Rule 1011(o) defines a proprietary trading firm as an Applicant with the following characteristics: (1) The Applicant is not required by Section 15(b)(8) of the Act to become a FINRA member but is a member of another registered securities exchange not registered solely under Section 6(g) of the Act; (2) all funds used or proposed to be used by the Applicant for trading are the Applicant's own capital, traded through the Applicant's own accounts; (3) the Applicant does not, and will not have ''customers,'' as that term is defined in Nasdaq Rule 0120(g); and (4) all Principals and Representatives of the Applicant acting or to be acting in the capacity of a trader must be owners of, employees of, or contractors to the Applicant. ''Applicant'' is defined in Rule 1011(a).

[5] Such persons may also be subject to registration as an Equity Trader pursuant to Rule 1032(f), which requires successful completion of the Series 55 exam (for which the prerequisite is the Series 7 examination).

[6] 15 U.S.C. 78f(b).

[7] 15 U.S.C. 78(c)(3)(B) [sic].

[8] 15 U.S.C. 78f(b)(5).

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(6).

[11] *Id.*

Under Rule 19b–4(f)(6) of the Act,[12] a proposal does not become operative for 30 days after the date of its filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. The Exchange requests that the Commission waive the 30 day operative period for this filing so that it may become effective and operative upon filing with the Commission pursuant to Section 19(b)(3)(A) [13] of the Act and subparagraph (f)(6) thereunder. The Exchange believes waiving the 30-day operative delay is consistent with the protection of investors and the public interest as the waiver will allow the Exchange to apply NASDAQ Rule 1032(c) to all NASDAQ members, not just NOM participants, near the same time as other exchanges have established proprietary trading registration and qualification requirements. For the reasons stated above, the Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest and designates the proposal as operative upon filing.[14]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–NASDAQ–2011–107 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2011–107. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of NASDAQ. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make publicly available. All submissions should refer to File Number SR–NASDAQ–2011–107 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20371 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[12] *Id.*

[13] 15 U.S.C. 78s(b)(3)(A).

[14] For purposes only of waiving the operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f). *See also* 17 CFR 200.30–3(a)(59).

[15] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65043; File No. SR–Phlx-2011–104]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to the Extension of a Pilot Program Regarding Price Improvement XL

August 5, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1], and Rule 19b–4 [2] thereunder, notice is hereby given that on August 1, 2011, NASDAQ OMX PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III, below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend Exchange Rule 1080(n), Price Improvement XL (''PIXL^{SM}'') to extend, through July 18, 2012, a pilot program (the ''pilot'') concerning (i) The early conclusion of the PIXL Auction (as described below), and (ii) permitting orders of fewer than 50 contracts into the PIXL Auction. The current pilot is scheduled to expire August 31, 2011.

The text of the proposed rule change is available on the Exchange's Web site at *http://www.nasdaqtrader.com/micro.aspx?id=PHLXRulefilings*, at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to extend the pilot through July 18, 2012.

Background

The Exchange adopted PIXL in October, 2010 as a price-improvement mechanism on the Exchange.[3] PIXL is a

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 63027 (October 1, 2010), 75 FR 62160 (October 7, 2010)

component of the Exchange's fully automated options trading system, PHLX XL®[4] that allows an Exchange member (an ''Initiating Member'') to electronically submit for execution an order it represents as agent on behalf of a public customer, broker dealer, or any other entity (''PIXL Order'') against principal interest or against any other order it represents as agent (an ''Initiating Order'') provided it submits the PIXL Order for electronic execution into the PIXL Auction (''Auction'') pursuant to the Rule.

An Initiating Member may initiate a PIXL Auction by submitting a PIXL Order in one of three ways:

- First, the Initiating Member could submit a PIXL Order specifying a single price at which it seeks to execute the PIXL Order (a ''stop price'').
- Second, an Initiating Member could submit a PIXL Order specifying that it is willing to automatically match as principal or as agent on behalf of an Initiating Order the price and size of all trading interest and responses to the PIXL Auction Notification (''PAN,'' as described below) (''auto-match''), in which case the PIXL Order will be stopped at the National Best Bid/Offer ('' NBBO'') on the Initiating Order side of the market (if 50 contracts or greater) or, if less than 50 contracts, the better of: (i) The PHLX Best Bid/Offer (''PBBO'') price on the opposite side of the market from the PIXL Order improved by at least one minimum price improvement increment, or (ii) the PIXL Order's limit price (if the order is a limit order), provided in either case that certain circumstances are met and that such price is at least one increment better than the limit of an order on the book on the same side as the PIXL Order.
- Third, an Initiating Member could submit a PIXL Order specifying that it is willing to either: (i) Stop the entire order at a single stop price and auto-match PAN responses, as described below, together with trading interest, at a price or prices that improve the stop price to a specified price above or below which the Initiating Member will not trade (a ''Not Worse Than'' or ''NWT'' price); (ii) stop the entire order at a single stop price and auto-match all PAN responses and trading interest at or better than the stop price; or (iii) stop the entire order at the NBBO on the Initiating Order side (if 50 contracts or greater) or the better of: (A) The PBBO price on the opposite side of the market from the PIXL Order improved by one minimum price improvement increment, or (B) the PIXL Order's limit price (if the order is a limit order) on the Initiating Order side (if for less than 50 contracts), and auto-match PAN responses and trading interest at a price or prices that improve the stop price up to the NWT price. In all cases, if the PBBO on the same side of the market as the PIXL Order represents a limit order on the book, the stop price must be at least one minimum price improvement increment better than the booked limit order's limit price.

After the PIXL Order is entered, a PAN is broadcast and a one-second blind Auction ensues. Anyone may respond to the PAN by sending orders or quotes. At the conclusion of the Auction, the PIXL Order will be allocated at the best price(s).

Once the Initiating Member has submitted a PIXL Order for processing, such PIXL Order may not be modified or cancelled. Under any of the above circumstances, the Initiating Member's stop price or NWT price may be improved to the benefit of the PIXL Order during the Auction, but may not be cancelled[.]

After a PIXL Order has been submitted, a member organization submitting the order has no ability to control the timing of the execution. The execution is carried out by the Exchange's PHLX XL® automated options trading system and pricing is determined solely by the other orders and quotes that are present in the Auction.

The Pilot

Three components of the PILX system were approved by the Commission on a pilot basis: (1) Paragraphs (n)(i)(A)(2) and (n)(i)(B)(2) of Rule 1080, relating to auction eligibility requirements; (2) paragraphs (n)(ii)(B)(4) and (n)(ii)(D) of Rule 1080, relating to the early conclusion of the PIXL Auction; and (3) paragraph (n)(vii) of Rule 1080, stating that there shall be no minimum size requirement of orders entered into PIXL. The pilots were approved for a pilot period expiring on August 31, 2011.[5] The Exchange notes that during the pilot period it has been required to submit, and has been submitting, certain data periodically as required by the Commission, to provide supporting evidence that, among other things, there is meaningful competition for all size orders and that there is an active and liquid market functioning on the Exchange outside of the Auction mechanism.[6] The Exchange will continue to provide such data. The Exchange believes that, because the pilot has been operating for a relatively short amount of time, the proposed extension should afford the Commission additional time to evaluate the pilot.

The Exchange proposes to extend the pilot through July 18, 2012.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[7] in general and with Section 6(b)(5) of the Act,[8] in that it is designed to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest; and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers, or to regulate by virtue of any authority conferred by the Act matters not related to the purposes of the Act or the administration of the Exchange.

The Exchange believes that the proposed rule change is also consistent with Section 6(b)(8) of the Act[9] in that it does not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

Specifically, the Exchange believes that PIXL, including the rules to which the pilot applies, result in increased liquidity available at improved prices, with competitive final pricing out of the Initiating Member's complete control. The Exchange believes that PIXL promotes and fosters competition and affords the opportunity for price improvement to more options contracts.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not

(SR–Phlx–2010–108) (Order Granting Approval to a Proposed Rule Change Relating to a Proposed Price Improvement System, Price Improvement XL).

[4] This proposal refers to ''PHLX XL'' as the Exchange's automated options trading system. In May 2009 the Exchange enhanced the system and adopted corresponding rules referring to the system as ''Phlx XL II.'' *See* Securities Exchange Act Release No. 59995 (May 28, 2009), 74 FR 26750 (June 3, 2009) (SR–Phlx–2009–32). The Exchange intends to submit a separate technical proposed rule change that would change all references to the system from ''Phlx XL II'' to ''PHLX XL'' for branding purposes.

[5] *See supra* note 3.

[6] *See* Exchange Rule 1080(n)(vii).

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(5).

[9] 15 U.S.C. 78f(b)(8).

necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received from Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate, it has become effective pursuant to 19(b)(3)(A) of the Act [10] and Rule 19b–4(f)(6) [11] thereunder.

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2011–104 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

[10] 15 U.S.C. 78s(b)(3)(A).

[11] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

All submissions should refer to File Number SR–Phlx–2011–104. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington DC, 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Phlx–2011–104 and should be submitted on or before September 1, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[12]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–20363 Filed 8–10–11; 8:45 am]

BILLING CODE 8011–01–P

[12] 17 CFR 200.30–3(a)(12).

DEPARTMENT OF STATE

[Public Notice 7553]

Bureau of Educational and Cultural Affairs (ECA) Request for Grant Proposals: Study of the United States Institute on U.S. National Security Policymaking

Announcement Type: New Cooperative Agreement.

Funding Opportunity Number: ECA/A/E/USS–12–01.

Catalog of Federal Domestic Assistance Number: 19.401

DATES: *Key Dates:* January to March, 2012.

Application Deadline: October 11, 2011.

Executive Summary: The Branch for the Study of the U.S., Office of Academic Exchange Programs, Bureau of Educational and Cultural Affairs (ECA/A/E/USS), invites proposal submissions for the design and implementation of the Study of the United States Institute on U.S. National Security Policymaking. This institute will provide a multinational group of up to 18 experienced foreign university educators and other professionals with a deeper understanding of U.S. approaches to national security policymaking, past and present, in order to strengthen curricula and to improve the quality of teaching about the United States at universities and other institutions abroad. The institute should be an intensive, academically rigorous program for scholars and other professionals from outside the United States, and should have a central theme and a strong contemporary component.

I. Funding Opportunity Description

Authority

Overall grant making authority for this program is contained in the Mutual Educational and Cultural Exchange Act of 1961, Public Law 87–256, as amended, also known as the Fulbright-Hays Act. The purpose of the Act is ''to enable the Government of the United States to increase mutual understanding between the people of the United States and the people of other countries * * *; to strengthen the ties which unite us with other nations by demonstrating the educational and cultural interests, developments, and achievements of the people of the United States and other nations * * * and thus to assist in the development of friendly, sympathetic and peaceful relations between the United States and the other countries of the world.'' The funding authority for the program above is provided through legislation.

Purpose: Study of the U.S. Institutes for scholars are intended to offer up to 18 foreign scholars and other professionals, whose professional work focuses in whole or in substantial part on the United States, the opportunity to deepen their understanding of American society, culture, and institutions. The ultimate goal is to strengthen curricula, to improve the quality of teaching, and to broaden understanding of U.S. national security policymaking in universities and other institutions of influence abroad.

The Bureau is seeking detailed proposals for a Study of the United States Institute on U.S. National Security Policymaking from colleges, universities, consortia of colleges and universities, and other not-for-profit academic organizations that have an established reputation in one or more of the following fields: Political science, international relations, law, military science, and/or other disciplines or sub-disciplines related to U.S. National Security. The institute should be organized around a central theme or themes in U.S. national security policy planning and formulation and should illuminate contemporary political, social, and economic debates in American society.

This Study of the United States Institute program should:

(1) Provide participants with a survey of contemporary scholarship within the institute's governing academic discipline. The proposal should describe how current scholarly debates within the field will be presented;

(2) Give participants a multi-dimensional examination of U.S. society and institutions that reflects a broad and balanced range of perspectives and responsible views from scholars and other professionals, such as government officials, and private practitioners; and,

(3) Ensure access to library and material resources that will enable participants to continue their research, study, and curriculum development upon returning to their home institutions.

Program Description: The Study of the U.S. Institute on U.S. National Security Policymaking should provide participants an opportunity to increase their understanding of the foundations and formulation of U.S. national security policy, U.S. views on basic U.S. national security and defense requirements, and how those views have evolved in the post-Cold War era and within the context of current counterterrorism strategies. This multi-disciplinary program should examine historical, political, geographic, and economic factors involved in U.S. national security policymaking.

Overview: The program should be six weeks in length; participants will spend approximately four weeks at the host institution, and approximately two weeks on the educational study tour, including four to five days in Washington, DC, at the conclusion of the Institute. This intensive, academically rigorous program should integrate lectures, readings, seminar discussions, regional travel, and site visits. The institute also should include opportunities for limited but well-directed independent research. Proposals should describe a thematically coherent program that maximizes institutional strengths, faculty expertise, and resources, as well as recognized scholars and experts from throughout the United States.

The program must conform with Bureau requirements and guidelines outlined in the Solicitation Package. Support for bureau programs is subject to the availability of funds. One award of up to $290,000 will support this institute.

Participants: Participants will be diverse in professional position and travel experience abroad. While participants may not have in-depth knowledge of the particular institute program theme, they will likely have had exposure to the relevant discipline and some experience teaching about the United States.

Participants will be drawn from all regions of the world and will be fluent or proficient in the English language. Fulbright Commissions and U.S. Embassies abroad will nominate candidates, and final selections will be made by the Bureau. A final list of participants will be sent to the recipient institution.

Program Dates: The anticipated award date for this Cooperative Agreement will be on or about December 1, 2011. The institute should be approximately 44 days in length (including participant arrival and departure days), should begin in early January, and end in late February or early March 2012.

Program Guidelines: The conception and structure of the institute agenda is the responsibility of the recipient, and it is essential that proposals provide a detailed and comprehensive narrative describing the objectives of the institute; the title, scope and content of each session; planned site visits; and how each session relates to the overall institute theme. Proposals must include a syllabus that indicates the subject matter for each lecture, panel discussion, group presentation, or other activity. The syllabus also should confirm or provisionally identify proposed speakers, trainers, and session leaders, and clearly show how assigned readings will advance the goals of each session. Overall, proposals will be reviewed on the basis of their responsiveness to RFGP criteria, coherence, clarity, and attention to detail. The accompanying Project Objectives, Goals, and Implementation (POGI) document provides program-specific guidelines that all proposals must address fully.

Please note: In a Cooperative Agreement, the Branch for the Study of the United States is substantially involved in program activities above and beyond routine grant monitoring. The Branch will assume the following responsibilities for the institute: participating in the selection of participants; overseeing the institute through one or more site visits; debriefing participants in Washington, DC at the conclusion of the institute; and engaging in follow-on communication with the participants after they return to their home countries (see POGI document for additional details). The Branch may request that the recipient make modifications to the academic residency and/or educational travel components of the program. The recipient will be required to obtain approval of significant program changes in advance of their implementation.

II. Award Information

Type of Award: Cooperative Agreement. ECA's level of involvement in this program is listed under number I above.

Fiscal Year Funds: FY–12.

Approximate Total Funding: $290,000.

Approximate Number of Awards: 1.

Approximate Average Award: $290,000.

Anticipated Award Date: Pending availability of funds, November 1, 2011.

Anticipated Project Completion Date: March 31, 2012 for the program; alumni programming available until December 31, 2012.

Additional Information: Pending successful implementation of this program and the availability of funds in subsequent fiscal years, it is ECA's intent to renew this cooperative agreement for two additional fiscal years, before openly competing it again.

III. Eligibility Information

III.1. Eligible applicants: Applications may be submitted by public and private U.S. colleges, universities, and other not-for-profit academic organizations that have an established reputation in a field or discipline related to the specific program theme, and which meet the provisions described in Internal Revenue Code section 26 U.S.C. 501(c)(3).

III.2. Cost Sharing or Matching Funds: There is no minimum or maximum percentage required for this competition. However, the Bureau encourages applicants to provide maximum levels of cost sharing and funding in support of its programs.

When cost sharing is offered, it is understood and agreed that the applicant must provide the amount of cost sharing as stipulated in its proposal and later included in an approved agreement. Cost sharing may be in the form of allowable direct or indirect costs. For accountability, you must maintain written records to support all costs which are claimed as your contribution, as well as costs to be paid by the Federal government. Such records are subject to audit. The basis for determining the value of cash and in-kind contributions must be in accordance with OMB Circular A–110, (Revised), Subpart C.23—Cost Sharing and Matching. In the event you do not provide the minimum amount of cost sharing as stipulated in the approved budget, ECA's contribution will be reduced in like proportion.

III.3. Other Eligibility Requirements: (a.) Bureau grant guidelines require that organizations with less than four years experience in conducting international exchanges be limited to $60,000 in Bureau funding. ECA anticipates awarding one grant, in an amount up to $290,000 to support program and administrative costs required to implement this exchange program. Therefore, organizations with less than four years experience in conducting international exchanges are ineligible to apply under this competition. The Bureau encourages applicants to provide maximum levels of cost sharing and funding in support of its programs.

(b.) Technical Eligibility: All proposals must comply with the following or they will result in your proposal being declared technically ineligible and given no further consideration in the review process: The project director or one of the key program staff responsible for the academic program must have an advanced degree in political science, international relations, law, military science, and/or other disciplines or sub-disciplines related to the program themes, and; Staff escorts traveling under the Cooperative Agreement must have demonstrated qualifications to perform this service.

IV. Application and Submission Information

Note: Please read the complete announcement before sending inquiries or submitting proposals. Once the RFGP deadline has passed, Bureau staff may not discuss this competition with applicants until the proposal review process has been completed.

IV.1. Contact Information To Request an Application Package: Please contact the Branch for the Study of the United States, ECA/A/E/USS, Fourth Floor, U.S. Department of State, SA–5, 2200 C Street, NW., Washington, DC 20037, (202) 632–3339 to request a Solicitation Package. Please refer to the Funding Opportunity Number ECA/A/E/USS–12–01 located at the top of this announcement when making your request.

Alternatively, an electronic application package may be obtained from *grants.gov*. Please see section IV.3f for further information.

The Solicitation Package contains the Proposal Submission Instruction (PSI) document which consists of required application forms, and standard guidelines for proposal preparation.

It also contains the Project Objectives, Goals, and Implementation (POGI) document, which provides specific information, award criteria, and budget instructions tailored to this competition.

Please specify Kevin H. Orchison and refer to the Funding Opportunity Number ECA/A/E/USS–12–01 located at the top of this announcement on all other inquiries and correspondence.

IV.2. To Download a Solicitation Package via Internet: The entire Solicitation Package may be downloaded from the Bureau's Web site at *http://exchanges.state.gov/grants/open2.html*, or from the *Grants.gov* Web site at *http://www.grants.gov*.

Please read all information before downloading.

IV.3. Content and Form of Submission: Applicants must follow all instructions in the Solicitation Package. The application should be submitted per the instructions under IV.3f. ''Application Deadline and Methods of Submission'' section below.

IV.3a. You are required to have a Dun and Bradstreet Data Universal Numbering System (DUNS) number to apply for a grant or Cooperative Agreement from the U.S. Government. This number is a nine-digit identification number, which uniquely identifies business entities. Obtaining a DUNS number is easy and there is no charge. To obtain a DUNS number, access *http://www.dunandbradstreet.com* or call 1–866–705–5711. Please ensure that your DUNS number is included in the appropriate box of the SF–424 which is part of the formal application package.

IV.3b. All proposals must contain an executive summary, proposal narrative, and budget.

Please Refer to the Solicitation Package. It contains the mandatory Proposal Submission Instructions (PSI) document and the Project Objectives, Goals, and Implementation (POGI) document for additional formatting and technical requirements.

IV.3c. All federal award recipients and sub-recipients must maintain current registrations in the Central Contractor Registration (CCR) database and have a Dun and Bradstreet Data Universal Numbering System (DUNS) number. Recipients and sub-recipients must maintain accurate and up-to-date information in the CCR until all program and financial activity and reporting have been completed. All entities must review and update the information at least annually after the initial registration and more frequently if required information changes or another award is granted.

You must have nonprofit status with the IRS at the time of application. **Please note:** Effective January 7, 2009, all applicants for ECA federal assistance awards must include in their application the names of directors and/or senior executives (current officers, trustees, and key employees, regardless of amount of compensation). In fulfilling this requirement, applicants must submit information in one of the following ways:

(1) Those who file Internal Revenue Service Form 990, ''Return of Organization Exempt From Income Tax,'' must include a copy of relevant portions of this form.

(2) Those who do not file IRS Form 990 must submit information above in the format of their choice.

In addition to final program reporting requirements, award recipients will also be required to submit a one-page document, derived from their program reports, listing and describing their grant activities. For award recipients, the names of directors and/or senior executives (current officers, trustees, and key employees), as well as the one-page description of grant activities, will be transmitted by the State Department to OMB, along with other information required by the Federal Funding Accountability and Transparency Act (FFATA), and will be made available to the public by the Office of Management and Budget on its *USASpending.gov* Web site as part of ECA's FFATA reporting requirements.

If your organization is a private nonprofit which has not received a grant or Cooperative Agreement from ECA in the past three years, or if your organization received nonprofit status from the IRS within the past four years, you must submit the necessary documentation to verify nonprofit status as directed in the PSI document. Failure to do so will cause your proposal to be declared technically ineligible.

IV.3d. Please take into consideration the following information when preparing your proposal narrative:

IV.3d.1. Adherence to All Regulations Governing the J Visa

The Bureau of Educational and Cultural Affairs places critically important emphases on the security and proper administration of the Exchange Visitor (J visa) Programs and adherence by award recipients and sponsors to all regulations governing the J visa. Therefore, proposals should demonstrate the applicant's capacity to meet all requirements governing the administration of the Exchange Visitor Programs as set forth in 22 CFR 62, including the oversight of Responsible Officers and Alternate Responsible Officers, screening and selection of program participants, provision of pre-arrival information and orientation to participants, monitoring of participants, proper maintenance and security of forms, record-keeping, reporting and other requirements.

ECA will be responsible for issuing DS–2019 forms to participants in this program.

A copy of the complete regulations governing the administration of Exchange Visitor (J) programs is available at *http://exchanges.state.gov* or from:

Office of Designation, Private Sector Programs Division, U.S. Department of State, ECA/EC/D/PS, SA–5, 5th Floor, 2200 C Street, NW., Washington, DC 20037.

Please refer to Solicitation Package for further information.

IV.3d.2. Diversity, Freedom and Democracy Guidelines

Pursuant to the Bureau's authorizing legislation, programs must maintain a non-political character and should be balanced and representative of the diversity of American political, social, and cultural life. ''Diversity'' should be interpreted in the broadest sense and encompass differences including, but not limited to ethnicity, race, gender, religion, geographic location, socio-economic status, and disabilities. Applicants are strongly encouraged to adhere to the advancement of this principle both in program administration and in program content. Please refer to the review criteria under the 'Support for Diversity' section for specific suggestions on incorporating diversity into your proposal. Public Law 104–319 provides that ''in carrying out programs of educational and cultural exchange in countries whose people do not fully enjoy freedom and democracy,'' the Bureau ''shall take appropriate steps to provide opportunities for participation in such programs to human rights and democracy leaders of such countries.'' Public Law 106–113 requires that the governments of the countries described above do not have inappropriate influence in the selection process. Proposals should reflect advancement of these goals in their program contents, to the full extent deemed feasible.

IV.3d.3. Program Monitoring and Evaluation

Proposals must include a plan to monitor and evaluate the project's success, both as the activities unfold and at the end of the program. The Bureau recommends that your proposal include a draft survey questionnaire or other technique plus a description of a methodology to use to link outcomes to original project objectives. The Bureau expects that the recipient organization will track participants or partners and be able to respond to key evaluation questions, including satisfaction with the program, learning as a result of the program, changes in behavior as a result of the program, and effects of the program on institutions (institutions in which participants work or partner institutions). The evaluation plan should include indicators that measure gains in mutual understanding as well as substantive knowledge.

Successful monitoring and evaluation depend heavily on setting clear goals and outcomes at the outset of a program. Your evaluation plan should include a description of your project's objectives, your anticipated project outcomes, and how and when you intend to measure these outcomes (performance indicators). The more that outcomes are ''smart'' (specific, measurable, attainable, results-oriented, and placed in a reasonable time frame), the easier it will be to conduct the evaluation. You should also show how your project objectives link to the goals of the program described in this RFGP.

Your monitoring and evaluation plan should clearly distinguish between program *outputs* and *outcomes. Outputs* are products and services delivered, often stated as an amount. Output information is important to show the scope or size of project activities, but it cannot substitute for information about progress towards outcomes or the results achieved. Examples of outputs include the number of people trained or the number of seminars conducted. *Outcomes,* in contrast, represent specific results a project is intended to achieve and is usually measured as an extent of change. Findings on outputs and outcomes should both be reported, but the focus should be on outcomes.

We encourage you to assess the following four levels of outcomes, as they relate to the program goals set out in the RFGP (listed here in increasing order of importance):

1. *Participant satisfaction* with the program and exchange experience.

2. *Participant learning,* such as increased knowledge, aptitude, skills, and changed understanding and attitude. Learning includes both substantive (subject-specific) learning and mutual understanding.

3. *Participant behavior,* concrete actions to apply knowledge in work or community; greater participation and responsibility in civic organizations; interpretation and explanation of experiences and new knowledge gained; continued contacts between participants, community members, and others.

4. *Institutional changes,* such as increased collaboration and partnerships, policy reforms, new programming, and organizational improvements.

Please note: Consideration should be given to the appropriate timing of data collection for each level of outcome. For example, satisfaction is usually captured as a short-term outcome, whereas behavior and institutional changes are normally considered longer-term outcomes.

Overall, the quality of your monitoring and evaluation plan will be judged on how well it (1) Specifies intended outcomes; (2) gives clear descriptions of how each outcome will be measured; (3) identifies when particular outcomes will be measured; and (4) provides a clear description of the data collection strategies for each outcome (*i.e.,* surveys, interviews, or focus groups). (Please note that evaluation plans that deal only with the first level of outcomes [satisfaction] will be deemed less competitive under the present evaluation criteria.)

Recipient organizations will be required to provide reports analyzing their evaluation findings to the Bureau in their regular program reports. All data collected, including survey responses and contact information, must be maintained for a minimum of three years and provided to the Bureau upon request.

IV.3e. Please take the following information into consideration when preparing your budget:

IV.3e.1. Applicants must submit SF–424A—''Budget Information—Non-Construction Programs'' along with a comprehensive budget for the entire program. Awards for the Institute on National Security Policymaking may not exceed $290,000, and administrative costs should be no more than approximately $95,000. There must be a summary budget as well as breakdowns reflecting both administrative and program budgets. Applicants may provide separate sub-budgets for each program component, phase, location, or activity to provide clarification.

IV.3e.2. Allowable costs for the program include the following:

(1) Institute staff salary and benefits.

(2) Participant housing and meals.

(3) Participant travel and per diem.

(4) Textbooks, educational materials, and admissions fees.

(5) Honoraria for guest speakers.

(6) Follow-on programming for alumni of Study of the United States programs.

Please refer to the Solicitation Package for complete budget guidelines and formatting instructions.

IV.3f. Application Deadline and Methods of Submission

Application Deadline Date: October 11, 2011.

Reference Number: ECA/A/E/USS–12–01.

Methods of Submission: Applications may be submitted in one of two ways:

(1.) In hard-copy, via a nationally recognized overnight delivery service (*i.e.,* Federal Express, UPS, Airborne Express, or U.S. Postal Service Express Overnight Mail, *etc.*), or

(2.) electronically through *http://www.grants.gov*.

Along with the Project Title, all applicants must enter the above Reference Number in Box 11 on the SF–424 contained in the mandatory Proposal Submission Instructions (PSI) of the solicitation document.

IV.3f.1. Submitting Printed Applications

Applications must be shipped no later than the above deadline. Delivery services used by applicants must have in-place, centralized shipping identification and tracking systems that may be accessed via the Internet and delivery people who are identifiable by commonly recognized uniforms and delivery vehicles. Proposals shipped on or before the above deadline but received at ECA more than seven days after the deadline will be ineligible for further consideration under this competition. Proposals shipped after the established deadlines are ineligible for consideration under this competition. ECA will *not* notify you upon receipt of application. It is each applicant's responsibility to ensure that each package is marked with a legible tracking number and to monitor/confirm delivery to ECA via the Internet. Delivery of proposal packages *may not* be made via local courier service or in person for this competition. Faxed documents will not be accepted at any time. Only proposals submitted as stated above will be considered.

Important Note: When preparing your submission please make sure to include one extra copy of the completed SF–424 form and place it in an envelope addressed to ''ECA/EX/PM''.

The original and six (6) copies of the application should be sent to:

Program Management Division, ECA–IIP/EX/PM, Ref.: ECA/A/E/USS–12–01, SA–5, Floor 4, Department of State, 2200 C Street, NW., Washington, DC 20037.

IV.3f.2. Submitting Electronic Applications

Applicants have the option of submitting proposals electronically through *Grants.gov* (*http://www.grants.gov*). Complete solicitation packages are available at *Grants.gov* in the ''Find'' portion of the system.

Please Note: ECA bears no responsibility for applicant timeliness of submission or data errors resulting from transmission or conversion processes for proposals submitted via *Grants.gov*.

Please follow the instructions available in the 'Get Started' portion of the site (*http://www.grants.gov/GetStarted*).

Several of the steps in the *Grants.gov* registration process could take several weeks. Therefore, applicants should check with appropriate staff within their organizations immediately after reviewing this RFGP to confirm or determine their registration status with *Grants.gov.*

Once registered, the amount of time it can take to upload an application will vary depending on a variety of factors including the size of the application and the speed of your Internet connection. In addition, validation of an electronic submission via *Grants.gov* can take up to two business days.

Therefore, we strongly recommend that you not wait until the application deadline to begin the submission process through Grants.gov.

The *Grants.gov* Web site includes extensive information on all phases/aspects of the *Grants.gov* process, including an extensive section on frequently asked questions, located under the ''For Applicants'' section of the Web site. ECA strongly recommends that all potential applicants review thoroughly the *Grants.gov* Web site, well in advance of submitting a proposal through the *Grants.gov* system. ECA bears no responsibility for data errors resulting from transmission or conversion processes.

Direct all questions regarding *Grants.gov* registration and submission to:

Grants.gov Customer Support. *Contact Center Phone:* 800–518–4726. *Business Hours:* Monday–Friday, 7 a.m.–9 p.m. Eastern Time. *E-mail: support@grants.gov.*

Applicants have until midnight (12:00 a.m.), Washington, DC time of the closing date to ensure that their entire application has been uploaded to the *Grants.gov* site. There are no exceptions to the above deadline. Applications uploaded to the site after midnight of the application deadline date will be automatically rejected by the grants.gov system, and will be technically ineligible.

Please refer to the *Grants.gov* Web site, for definitions of various ''application statuses'' and the difference between a submission receipt and a submission validation. Applicants will receive a validation e-mail from *grants.gov* upon the successful submission of an application. Again, validation of an electronic submission via *Grants.gov* can take up to two business days. Therefore, we strongly recommend that you not wait until the application deadline to begin the submission process through Grants.gov. ECA will not notify you upon receipt of electronic applications.

It is the responsibility of all applicants submitting proposals via the *Grants.gov* web portal to ensure that proposals have been received by *Grants.gov* in their entirety, and ECA bears no responsibility for data errors resulting from transmission or conversion processes.

Optional—IV.3f.3. You may also state here any limitations on the number of applications that an applicant may submit and make it clear whether the limitation is on the submitting organization, individual program director or both.

IV.3g. Intergovernmental Review of Applications: Executive Order 12372 does not apply to this program.

V. Application Review Information

V.1. Review Process

The Bureau will review all proposals for technical eligibility. Proposals will be deemed ineligible if they do not fully adhere to the guidelines stated herein and in the Solicitation Package. All eligible proposals will be reviewed by the program office, as well as the Public Diplomacy section overseas, where appropriate. Eligible proposals will be subject to compliance with Federal and Bureau regulations and guidelines and forwarded to Bureau grant panels for advisory review. Proposals may also be reviewed by the Office of the Legal Adviser or by other Department elements. Final funding decisions are at the discretion of the Department of State's Assistant Secretary for Educational and Cultural Affairs. Final technical authority for Cooperative

Agreements resides with the Bureau's Grants Officer.

Technically eligible applications will be competitively reviewed according to the criteria stated below. These criteria are not rank ordered and all carry equal weight in the proposal evaluation:

1. *Quality of Program Plan and Ability to Achieve Program Objectives:* Proposals should exhibit originality, substance, precision, and relevance to the Bureau's mission. A detailed agenda and relevant work plan should demonstrate substantive undertakings and logistical capacity. Objectives should be reasonable, feasible, and flexible. Proposals should demonstrate clearly how the institution will meet the program's objectives and plan.

2. *Support for Diversity:* Proposals should demonstrate substantive support of the Bureau's policy on diversity. Achievable and relevant features should be cited in both program administration (program venue and program evaluation) and program content (orientation and wrap-up sessions, program meetings, presenters, and resource materials).

3. *Evaluation:* Proposals should include a plan to evaluate the activity's success, both as the activities unfold and at the end of the program. A draft survey questionnaire or other technique plus a description of a methodology to use to link outcomes to original project objectives is strongly recommended.

4. *Cost-effectiveness/Cost-sharing:* The overhead and administrative components of the proposal, including salaries and honoraria, should be kept as low as possible. All other items should be necessary and appropriate. Proposals should maximize cost-sharing through other private sector support, as well as institutional direct funding contributions.

5. *Institutional Track Record/Ability:* Proposals should demonstrate an institutional record of successful exchange programs, including responsible fiscal management and full compliance with all reporting requirements for past Bureau grants as determined by Bureau Grants Staff. The Bureau will consider the past performance of prior recipients and the demonstrated potential of new applicants. Proposed personnel and institutional resources should be fully qualified to achieve the project's goals.

6. *Follow-up and Follow-on Activities:* Proposals should discuss provisions made for follow-up with returned participants as a means of establishing longer-term individual and institutional linkages. Proposals also should provide a plan for continued follow-on activity (without Bureau support) ensuring that Bureau supported programs are not isolated events.

VI. Award Administration Information

VI.1a. Award Notices

Final awards cannot be made until funds have been appropriated by Congress, allocated and committed through internal Bureau procedures. Successful applicants will receive a Federal Assistance Award (FAA) from the Bureau's Grants Office. The FAA and the original proposal with subsequent modifications (if applicable) shall be the only binding authorizing document between the recipient and the U.S. Government. The FAA will be signed by an authorized Grants Officer, and mailed to the recipient's responsible officer identified in the application.

Unsuccessful applicants will receive notification of the results of the application review from the ECA program office coordinating this competition.

VI.2. Administrative and National Policy Requirements

Terms and Conditions for the Administration of ECA agreements include the following:

Office of Management and Budget Circular A–122, ''Cost Principles for Nonprofit Organizations.''

Office of Management and Budget Circular A–21, ''Cost Principles for Educational Institutions.''

OMB Circular A–87, ''Cost Principles for State, Local and Indian Governments''.

OMB Circular No. A–110 (Revised), Uniform Administrative Requirements for Grants and Agreements with Institutions of Higher Education, Hospitals, and other Nonprofit Organizations.

OMB Circular No. A–102, Uniform Administrative Requirements for Grants-in-Aid to State and Local Governments.

OMB Circular No. A–133, Audits of States, Local Government, and Non-profit Organizations.

Please reference the following Web sites for additional information:

http://www.whitehouse.gov/omb/grants.
http://fa.statebuy.state.gov

VI.3. *Reporting Requirements:* You must provide ECA with a hard copy original plus one copy of the following reports:

Mandatory:

(1) Quarterly financial reports; final program no more than 90 days after the expiration of the award;

(2) A concise, one-page final program report summarizing program outcomes no more than 90 days after the expiration of the award. This one-page report will be transmitted to OMB, and be made available to the public via OMB's USAspending.gov Web site—as part of ECA's Federal Funding Accountability and Transparency Act (FFATA) reporting requirements.

(3) A SF–PPR, ''Performance Progress Report'' Cover Sheet with all program reports.

Award recipients will be required to provide reports analyzing their evaluation findings to the Bureau in their regular program reports. (Please refer to IV. Application and Submission Instructions (IV.3.d.3) above for Program Monitoring and Evaluation information.)

All data collected, including survey responses and contact information, must be maintained for a minimum of three years and provided to the Bureau upon request.

All reports must be sent to the ECA Grants Officer and ECA Program Officer listed in the final assistance award document.

VII. Agency Contacts

For questions about this announcement, contact: Kevin H. Orchison, U.S. Department of State, Branch for the Study of the United States, ECA/A/E/USS, SA–5, Fourth Floor, ECA/A/E/USS–12–01, 2200 C Street, NW., Washington, DC 20522–0503, (202) 632–3339, *OrchisonKH@state.gov.*

All correspondence with the Bureau concerning this RFGP should reference the above title and number ECA/A/E/USS–12–01.

Please read the complete announcement before sending inquiries or submitting proposals. Once the RFGP deadline has passed, Bureau staff may not discuss this competition with applicants until the proposal review process has been completed.

VIII. Other Information:

Notice:

The terms and conditions published in this RFGP are binding and may not be modified by any Bureau representative. Explanatory information provided by the Bureau that contradicts published language will not be binding. Issuance of the RFGP does not constitute an award commitment on the part of the Government. The Bureau reserves the right to reduce, revise, or increase proposal budgets in accordance with the needs of the program and the availability of funds. Awards made will be subject to periodic reporting and evaluation requirements per section VI.3 above.

Dated: August 1, 2011.

J. Adam Ereli,

Principal Deputy Assistant Secretary, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2011–20310 Filed 8–10–11; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF STATE

[Public Notice 7554]

Culturally Significant Object Imported for Exhibition Determinations: ''Warhol: The Headlines''

ACTION: Notice, correction.

SUMMARY: On July 7, 2011, notice was published on page 39974 of the **Federal Register** (Volume 76, No. 130) of determinations made by the Department of State pertaining to the exhibition, ''Warhol: The Headlines.'' The referenced notice is corrected to add one additional object to be included in the exhibition. Pursuant to the authority vested in me by the Act of October 19, 1965 (79 Stat. 985; 22 U.S.C. 2459), Executive Order 12047 of March 27, 1978, the Foreign Affairs Reform and Restructuring Act of 1998 (112 Stat. 2681, *et seq.;* 22 U.S.C. 6501 note, *et seq.*), Delegation of Authority No. 234 of October 1, 1999, Delegation of Authority No. 236–3 of August 28, 2000 (and, as appropriate, Delegation of Authority No. 257 of April 15, 2003), I hereby determine that the additional object to be included in the exhibition ''Warhol: The Headlines,'' imported from abroad for temporary exhibition within the United States, is of cultural significance. The object is imported pursuant to a loan agreement with the foreign owner or custodian. I also determine that the exhibition or display of the exhibit object at the National Gallery of Art, Washington, DC, from on or about September 25, 2011, until on or about January 2, 2012, at The Andy Warhol Museum, Pittsburgh, Pennsylvania, from on or about October 14, 2012, until on or about January 6, 2013, and at possible additional exhibitions or venues yet to be determined, is in the national interest. I have ordered that Public Notice of these Determinations be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: For further information, including a description of the additional object, contact Paul W. Manning, Attorney-Adviser, Office of the Legal Adviser, U.S. Department of State (telephone: 202–632–6469). The mailing address is U.S. Department of State, SA–5, L/PD, Fifth Floor (Suite 5H03), Washington, DC 20522–0505.

Dated: August 4, 2011.

J. Adam Ereli,

Principal Deputy Assistant Secretary, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2011–20424 Filed 8–10–11; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No DOT–OST–2011–0145]

Notice of Market Assessment and Public Meeting for Digital Transportation Exchange

AGENCY: Office of the Secretary, DOT.

ACTION: Notice of Public Meeting and Request for Comments.

SUMMARY: In accordance with OMB Memoranda M10–06, ''Open Government Directive,'' the U.S. Department of Transportation (Department or DOT) is evaluating the feasibility and value of a new cloud-based platform to connect citizens, businesses, state and local governments, industry, entrepreneurs, researchers, and investors like never before—creating a thriving marketplace for digital transportation solutions. The Digital Transportation Exchange (DTE) will be a public exchange where citizens, businesses, state and local governments, industry, entrepreneurs, researchers, and investors will converge to find the best way to develop, fund and market the best digital products and services for the transportation industry—from very simple to very complex. Recognizing that transportation solutions are often adopted locally, this site will provide a single location for all of these local solutions to be showcased nationally, encouraging reuse, investment and improvement. DOT is seeking partners to develop, build and maintain this portal. As part of this evaluation, the Department invites the public to participate in a comment process designed to help the Department develop a feasible and high value concept for this portal and the partnership model designed to sustain it. The Department also will hold a stakeholder meeting to discuss and consider comments. Comments and suggestions from these two forums may be incorporated into a follow on procurement that will be released in 2011 to solicit partners.

DATES: The Department will receive comments from interested parties until September 23, 2011.

- Specifically, the Department will hold a stakeholder meeting beginning at 9:30 a.m. ET on September 16, 2011, at the DOT headquarters, to discuss the concept.
- Deadline to register to attend meeting in person/watch Web stream/listen by phone—September 2, 2011. Attendees are asked to RSVP for the meeting via e-mail (*Open@dot.gov*) and indicate how you intend to participate (via webcast, call in by phone, or in person). Additionally, please provide the following information if you intend to attend in person; if you are a U.S. Citizen please provide your name and agency/company. If you're not U.S. Citizen please provide your name, title or position, country of citizenship, date of birth, and passport number.
- Agenda released on *http://www.dot.gov/open/DTE*—September 12, 2011.
- Web streaming/call-in info distributed to registrants—September 12, 2011.
- Stakeholder Meeting—September 16—9:30 a.m.–2 p.m.

ADDRESSES: You may submit comments to the Department DOT–OST–2011–0145 by any of the following methods:

- *Online:* DTE Ideascale Community. *DTE.ideascale.com.* Participants can provide comments online, rate others' comments, and comment on others' comments throughout the entire comment period, starting from the release of this notice through September 23, 2011.
- *Mail:* Docket Management Facility; U.S. Department of Transportation, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001. If you submit comments by mail and would like to know that they reached the facility, please enclose a stamped, self-addressed envelope or postcard.
- *Hand Delivery or Courier:* West Building, Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC between 9 a.m. and 5 p.m. ET., Monday through Friday, except Federal holidays.
- *Fax* to DOT Docket Management Facility: 202–493–2251.
- *E-mail: open@dot.gov*

To avoid duplication, please use only one of these five methods. The DOT encourages commenters to use to Ideascale community as the preferred comment submission method. All comments received will be posted without change to the docket in *www.regulations.gov* and will include any personal information you provide.

DOT encourages you to read the full concept paper and supplemental materials that describe this concept in more detail at *http://www.dot.gov/open/DTE* before submitting comments. If you do not have access to the Internet, you may view the materials by visiting the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Mrs. Kristen Baldwin, Director, Resource Management Office, Office of the Chief Information Officer, 1200 New Jersey Avenue, SE., Washington, DC 20590. E-mail: *Open@dot.gov*

SUPPLEMENTARY INFORMATION:

Concept Overview

The U.S. Department of Transportation (Department or DOT) is evaluating the feasibility and value of a new cloud-based platform to coordinate, develop, and showcase identified issues and resulting solutions to current issues in the Transportation industry in collaboration with the public and non-traditional industry players and entrepreneurs. The goal of the DTE initiative is to simultaneously increase the supply of transportation solutions available, through injecting private capital and expanding the industry base, and the demand for those solutions, by involving consumers of those solutions including state and local government, individual citizens, and the transportation infrastructure industry.

DTE is intended to create an exchange across the Transportation industry—connecting people and technology for transportation innovation. Stakeholders could include: Citizens, businesses, state and local governments, industry, entrepreneurs, researchers, and investors. DTE is intended to drive collaboration across these stakeholder communities by identifying existing problems, establishing a one-stop-shop for resources to develop solutions, connecting users to develop partnerships, and then showcasing those solutions. It would present a consolidated view of existing transportation-related solutions as well as issues in need of a technology solution.

The community would be managed to engage and promote ideas, report back on implemented solutions, and connect with stakeholders. While digital transportation solutions exist in the public and private sector, these technology innovations are not easily shared across political jurisdictions and potential markets, nor are these solutions matched to investors that may help them scale. DTE will ''build a home'' for transportation technology innovation. More specifically, the functions that DTE might provide include, but are not limited to:

Prioritizing Problems: Help identify and prioritize major transportation problems by size and intensity through ideation and crowd sourcing from citizens, industry, operators, businesses, experts and academics.

Solutions Teaming: Encourage teaming of entrepreneurs, developers, experts and government entities to create innovative digital transportation strategies and plans for funding.

Funding and Financing: Attract attention of the investment community including angels, venture capitalists and strategic investors to digital transportation business plans for funding. Stimulate solution development through innovative funding mechanisms like prizes and competitions.

Market Development: Create a transportation focused service provider exchange consisting of legal, marketing, communications, accounting and other expertise. Increase the supply of solutions by involving non-traditional actors as well as the demand by drawing the attention of users and investors.

DOT is seeking partners to develop, build and maintain the DTE. Although the DOT will act as a partner in the management of the exchange, DTE will utilize strategic partnerships with industry leaders to provide an externally hosted solution. DOT is potentially looking to develop a public-private partnership to support this work. Partners would be expected to stand-up and sustain a business model over time, understanding DOT may not have funding to contribute. Please see the detailed description of this concept on *http://www.dot.gov/open/DTE* before submitting comments.

Stakeholder Participation and Request for Comments

DOT is interested in general comments pertaining to the concept paper and is also particularly interested in comments about the following questions:

- How would you use the DTE? What transportation topics should the DTE focus on? How do you think the concepts of using shared/interactive technology (DTE) can best be used in the transportation industry?
- Given what you currently know about the use of DTE related concepts, are there any additional functions that would be needed for you to use it most effectively?
- Can you suggest specific opportunities to build public/private partnerships as they relate to the DTE?
- How can in-person/face to face interactions compliment the online DTE? If so, what kinds of activities would best connect people and technology to stimulate transportation innovation?
- Who are the critical partners that should be involved in launching and maintaining the DTE to ensure its success?
- In your opinion, what are the greatest challenges for integrating the use of shared/interactive technology (DTE) in the transportation industry?
- What strategies would you use to stimulate innovation in this era of using shared/interactive technology in the transportation arena?

The preferred method for the submission of comments on these questions is through the ideascale site (*DTE.ideascale.com*) or at the public meeting, though alternative methods for submitting comments are described earlier in this notice.

Stakeholder Meeting Procedures

The meeting will begin with a discussion of Department's preliminary concept for DTE and a summary of comments received to date. After that, we plan to facilitate focused discussions on the issues identified earlier in this notice. The Department's Director of Public Engagement will preside over the meeting. Other senior officials will participate in this meeting as well to discussion issues pertaining to this project concept with stakeholders.

The meeting is designed to gather additional information for DTE concept and partnership. Therefore, the meeting will be conducted in an informal and non-adversarial manner. It is our intent that the meeting will provide an opportunity for the senior officials to interact with individuals or stakeholder representatives. To enable them to effectively participate in the meeting, they will need some information in advance. As a result, we are establishing the following process.

1. Preparing to Attend the Stakeholder Meeting:

a. Commenters are asked to RSVP for the meeting via e-mail (*Open@dot.gov*) by September 2, 2011 and indicate how you intend to participate (via webcast, call in by phone, or in person). Due to security requirements, all public attendees must register to ensure their access to the building. To register, contact Kristen Baldwin. If you intend to attend the meeting in person and are a U.S. citizen please RSVP with your name and agency/company. Foreign

National registrants must provide your full name, title, country of citizenship, date of birth, passport number, and passport expiration date when registering. Because seating space is limited, we may have to limit attendees in order of date and time of registration.

b. Please submit any initial comments in advance of the meeting through one of the mechanisms identified earlier in this notice. The initial comments should contain enough details to permit DOT officials to sufficiently prepare responses to, ask questions about, and discuss those comments.

c. The initial comments may be augmented anytime before the end of the full comment period.

d. Anyone who needs auxiliary aids and services, such as sign language interpreters, to effectively participate in the meeting should contact Ms. Baldwin as soon as possible.

2. Stakeholder Meeting:

a. After receiving the initial stakeholder comments, the Department will organize those suggestions by topic for discussion during the public meeting.

b. The Department will hold the meeting beginning at 9:30 a.m. ET on September 16, 2011 at the Department of Transportation, West Building, Ground Floor, DOT Conference Center, Oklahoma Room, 1200 New Jersey Avenue, SE., Washington, DC. We will make a meeting outline and agenda available on *http://www.dot.gov/open/DTE* by September 12, 2011 in advance of the meeting.

c. Attendees are encouraged to arrive early for processing through security. All participants and attendees must enter through the New Jersey Avenue entrance (West Building—at the corner of New Jersey Avenue and M Street, SE.). Photo identification is required and Foreign National attendees must bring their passports with them. Participants or attendees who have Federal government identification will still need to register to attend. To facilitate security screening, all participants and attendees are encouraged to limit the bags and other items (laptops, cameras, etc.) they bring into the building. Anyone exiting the building for any reason will be required to re-enter through the security checkpoint at the New Jersey Avenue entrance.

d. DOT does not offer visitor parking; we suggest that attendees consider using alternative means of transportation to the building. DOT Headquarters is served by Metrorail (Navy Yard station), Metrobus, DC Circulator, and taxi service. There are a number of private parking lots near the DOT building, but the DOT cannot guarantee the availability of parking spaces.

e. For those unable to attend the meeting in person, portions will be broadcast via Web streaming (with captioning) and over a listen-only phone line. Registrants will be given the Web URL or phone number on September 16, 2011. Because the number of people who can participate in Web streaming and by phone is limited, we will provide access in order of date and time of registration.

3. Other Written Comments:

The Department will continue to accept written comments through September 23, 2011. Those who do not wish to attend the stakeholder meeting may, of course, submit comments at any time during the comment period through the other methods identified earlier in this notice.

4. Follow-up Action by DOT:

We will place a transcript or summary of the stakeholder meeting on our Web site (*http://www.dot.gov/open/DTE*) as soon as possible after the end of the meeting; the record will be available in the docket on *http://www.regulations.gov.*

DOT IdeaScale Web Site

To provide the public with alternative means of providing feedback to DOT in ways that may better suit their needs, we have created a Web site using IdeaScale that will allow submissions to DOT in a less formal manner. This Web site will provide members of the public an opportunity to submit their ideas about our concept and partnership. Participants in this site may discuss one another's ideas and agree/disagree with others. This Web site may be particularly useful for individuals and small entities that prefer a less formal method of submitting ideas to DOT. It may also assist participants in refining their suggestions and gathering additional information or data to support those suggestions.

To ensure that ideas are most useful, you should include a description of any concerns regarding the concept (e.g. it is duplicative, too costly, etc.), any supporting information (e.g., actual cost or benefit data, references to duplicative slides, etc. * * *), and comments on the particular issues identified in the concept overview section of this notice that would assist DOT in making a decision. Please also include in your comment whether you found this Web site useful for your purposes, so that we can best plan how to deploy DOT's scarce resources to most effectively reach the public in the future. To go directly to the IdeaScale Web site use the following link: *DTE.ideascale.com.*

Follow-Up Action by DOT

As soon as possible after the stakeholder meeting and the close of the comment period, taking account of the number of comments received and the complexity of issues raised, DOT will publish a report providing at least a brief response to the comments we receive, including a description of any further action we intend to take on the initiative's Web site at *http://www.dot.gov/open/DTE.*

Issue Date: August 5, 2011.

Kristen Baldwin,

Director, Business Management Office, Chief Information Officer, U.S. Department of Transportation.

[FR Doc. 2011–20397 Filed 8–10–11; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

[Docket No. DOT–NHTSA–2011–0113, Notice 1]

Notice of Receipt of Petition for Decision That Nonconforming 2009 Dodge RAM 1500 Laramie Crew Cab Trucks Manufactured for the Mexican Market Are Eligible for Importation

AGENCY: National Highway Traffic Safety Administration, DOT.

ACTION: Notice of receipt of petition.

SUMMARY: This document announces receipt by the National Highway Traffic Safety Administration (NHTSA) of a petition for a decision that 2009 Dodge RAM 1500 Laramie Crew Cab trucks manufactured for the Mexican market (2009 Dodge RAM 1500 Mexican trucks), that were not originally manufactured to comply with all applicable Federal Motor Vehicle Safety Standards (FMVSS), are eligible for importation into the United States because they are substantially similar to vehicles that were originally manufactured for sale in the United States and that were certified by their manufacturer as complying with the safety standards (the U.S.-certified version of the 2009 Dodge RAM 1500 Laramie Crew Cab trucks) and they are capable of being readily altered to conform to the standards.

DATES: The closing date for comments on the petition is September 12, 2011.

ADDRESSES: Comments should refer to the docket and notice numbers above and be submitted by any of the following methods:

• *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the online instructions for submitting comments.

- *Mail:* Docket Management Facility: U.S. Department of Transportation, 1200 New Jersey Avenue, SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., between 9 a.m. and 5 p.m. ET, Monday through Friday, except Federal holidays.
- *Fax:* 202–493–2251.

Instructions: Comments must be written in the English language, and be no greater than 15 pages in length, although there is no limit to the length of necessary attachments to the comments. If comments are submitted in hard copy form, please ensure that two copies are provided. If you wish to receive confirmation that your comments were received, please enclose a stamped, self-addressed postcard with the comments. Note that all comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided. Please see the Privacy Act heading below.

Privacy Act: Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78).

How to read comments submitted to the docket: You may read the comments received by Docket Management at the address and times given above. You may also view the documents from the Internet at *http://www.regulations.gov.*

Follow the online instructions for accessing the dockets. The docket ID number and title of this notice are shown at the heading of this document notice. Please note that even after the comment closing date, we will continue to file relevant information in the Docket as it becomes available. Further, some people may submit late comments. Accordingly, we recommend that you periodically search the Docket for new material.

FOR FURTHER INFORMATION CONTACT: Coleman Sachs, Office of Vehicle Safety Compliance, NHTSA (202–366–3151).

SUPPLEMENTARY INFORMATION:

Background

Under 49 U.S.C. 30141(a)(1)(A), a motor vehicle that was not originally manufactured to conform to all applicable FMVSS shall be refused admission into the United States unless NHTSA has decided that the motor vehicle is substantially similar to a motor vehicle originally manufactured for importation into and sale in the United States, certified under 49 U.S.C. 30115, and of the same model year as the model of the motor vehicle to be compared, and is capable of being readily altered to conform to all applicable FMVSS.

Petitions for eligibility decisions may be submitted by either manufacturers or importers who have registered with NHTSA pursuant to 49 CFR part 592. As specified in 49 CFR 593.7, NHTSA publishes notice in the **Federal Register** of each petition that it receives, and affords interested persons an opportunity to comment on the petition. At the close of the comment period, NHTSA decides, on the basis of the petition and any comments that it has received, whether the vehicle is eligible for importation. The agency then publishes this decision in the **Federal Register**.

Wallace Environmental Testing Laboratories, Inc. of Houston, Texas (WETL) (Registered Importer 90–005) has petitioned NHTSA to decide whether nonconforming 2009 Dodge RAM 1500 Mexican trucks are eligible for importation into the United States. The vehicles which WETL believes are substantially similar are 2009 Dodge RAM 1500 Laramie Crew Cab trucks that were manufactured for sale in the United States and certified by their manufacturer as conforming to all applicable FMVSS.

The petitioner claims that it carefully compared non-U.S. certified 2009 Dodge RAM 1500 Mexican trucks to their U.S.-certified counterparts, and found the vehicles to be substantially similar with respect to compliance with most FMVSS.

WETL submitted information with its petition intended to demonstrate that non-U.S. certified 2009 Dodge RAM 1500 Mexican trucks, as originally manufactured, conform to many FMVSS in the same manner as their U.S. certified counterparts, or are capable of being readily altered to conform to those standards.

Specifically, the petitioner claims that non-U.S. certified 2009 Dodge RAM 1500 Mexican trucks are identical to their U.S.-certified counterparts with respect to compliance with Standard Nos. 101 *Controls and Displays,* 102 *Transmission Shift Lever Sequence, Starter Interlock, and Transmission Braking Effect,* 103 *Windshield Defrosting and Defogging Systems,* 104 *Windshield Wiping and Washing Systems,* 106 *Brake Hoses,* 111 *Rearview Mirrors,* 113 *Hood Latch System,* 114 *Theft Protection,* 116 *Motor Vehicle Brake Fluids,* 118 *Power-Operated Window, Partition, and Roof Panel Systems,* 120 *Tire Selection and Rims for Motor Vehicles Other than Passenger Cars,* 124 *Accelerator Control Systems,* 135 *Light Vehicle Brake Systems,* 138 *Tire Pressure Monitoring Systems,* 201 *Occupant Protection in Interior Impact,* 202 *Head Restraints,* 204 *Steering Control Rearward Displacement,* 205 *Glazing Materials,* 206 *Door Locks and Door Retention Components,* 207 *Seating Systems,* 208 *Occupant Crash Protection* 209 *Seat Belt Assemblies,* 210 *Seat Belt Assembly Anchorages,* 212 *Windshield Mounting,* 214 *Side Impact Protection,* 216 *Roof Crush Resistance,* 219 *Windshield Zone Intrusion,* 225 *Child Restraint Anchorage Systems,* 301 *Fuel System Integrity,* and 302 *Flammability of Interior Materials.*

Petitioner also contends that the vehicle is capable of being readily altered to meet the following standard, in the manner indicated:

Standard No. 108 *Lamps, Reflective Devices and Associated Equipment:* inspection of all vehicles and installation of U.S.-model lamps on vehicles not already so equipped to ensure that the vehicles meet the requirements of this standard.

The petitioner additionally states that a vehicle identification plate must be affixed to the vehicles near the left windshield post to meet the requirements of 49 CFR part 565.

All comments received before the close of business on the closing date indicated above will be considered, and will be available for examination in the docket at the above addresses both before and after that date. To the extent possible, comments filed after the closing date will also be considered. Notice of final action on the petition will be published in the **Federal Register** pursuant to the authority indicated below.

Authority: 49 U.S.C. 30141(a)(1)(A) and (b)(1); 49 CFR 593.8; delegations of authority at 49 CFR 1.50 and 501.8.

Issued on: August 5, 2011.

Claude H. Harris,

Director, Office of Vehicle Safety Compliance.

[FR Doc. 2011–20368 Filed 8–10–11; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF THE TREASURY

Office of the Secretary

List of Countries Requiring Cooperation With an International Boycott

In accordance with section 999(a)(3) of the Internal Revenue Code of 1986, the Department of the Treasury is publishing a current list of countries which require or may require participation in, or cooperation with, an international boycott (within the meaning of section 999(b)(3) of the Internal Revenue Code of 1986).

On the basis of the best information currently available to the Department of the Treasury, the following countries require or may require participation in, or cooperation with, an international boycott (within the meaning of section 999(b)(3) of the Internal Revenue Code of 1986).

Kuwait, Lebanon, Libya, Qatar, Saudi Arabia, Syria, United Arab Emirates, Yemen, Republic of

Iraq is not included in this list, but its status with respect to future lists remains under review by the Department of the Treasury.

Dated: August 1, 2011.

Michael J. Caballero,

International Tax Counsel, (Tax Policy).

[FR Doc. 2011–20318 Filed 8–10–11; 8:45 am]

BILLING CODE 4810–25–M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 8621–A

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 8621–A, Return by a Shareholder Making Certain Late Elections To End Treatment as a Passive Foreign Investment Company.

DATES: Written comments should be received on or before October 11, 2011 to be assured of consideration.

ADDRESSES: Direct all written comments to Yvette Lawrence, Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to R. Joseph Durbala, (202) 622–3634, at Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet at *RJoseph.Durbala@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Return by a Shareholder Making Certain Late Elections To End Treatment as a Passive Foreign Investment Company.

OMB Number: 1545–1950.

Form Number: 8621–A.

Abstract: Form 8621–A is necessary for certain taxpayers/shareholders who are investors in passive foreign investment companies (PFIC's) to request late deemed sale or late deemed dividend elections (late purging elections) under Reg. 1.1298–3(e). The form provides a taxpayer/shareholder the opportunity to fulfill the requirements of the regulation in making the election by asserting the following: (i) The election is being made before an IRS agent has raised on audit the PFIC status of the foreign corporation for any taxable year of the taxpayer/shareholder; (ii) the taxpayer/shareholder is agreeing (by submitting Form 8621–A) to eliminate any prejudice to the interests of the U.S. government on account of the taxpayer/shareholder's inability to make timely purging elections; and (iii) the taxpayer/shareholder shows as a balance due on Form 8621–A an amount reflecting tax plus interest as determined under Reg. 1.1298(e)(3).

Current Actions: There is no change to the form previously approved by OMB. However, filing estimates indicate that a decrease in the estimated number of responses is necessary. We have decreased the estimated number of responses to 12 per year. This results in a total estimated burden decrease of 42,837 hours per year. This form is being submitted for renewal purposes.

Type of Review: Revision of a currently approved collection.

Affected Public: Individuals and Households, Businesses and other for-profit organizations.

Estimated Number of Respondents: 12.

Estimated Time per Respondent: 65 hours, 24 minutes.

Estimated Total Annual Burden Hours: 785.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: August 2, 2011.

Yvette Lawrence,

IRS Reports Clearance Officer.

[FR Doc. 2011–20379 Filed 8–10–11; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 8846

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the

Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 8846, Credit for Employer Social Security and Medicare Taxes Paid on Certain Employee Tips.

DATES: Written comments should be received on or before October 11, 2011 to be assured of consideration.

ADDRESSES: Direct all written comments to Yvette Lawrence, Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to R. Joseph Durbala, at (202) 622–3634, or at Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet at *RJoseph.Durbala@irs.gov*.

SUPPLEMENTARY INFORMATION:

Title: Credit for Employer Social Security and Medicare Taxes Paid on Certain Employee Tips.

OMB Number: 1545–1414.

Form Number: 8846.

Abstract: Employers in food or beverage establishments where tipping is customary can claim an income tax credit for the amount of social security and Medicare taxes paid (employer's share) on tips employees reported, other than on tips used to meet the minimum wage requirement. Form 8846 is used by employers to claim the credit and by the IRS to verify that the credit is computed correctly.

Current Actions: Lines 7 through 11 will be removed, since the passive activity limit and the carryover amounts will be calculated on Form 3800. This and other editorial changes will result in a total burden increase of 18,228 hours.

Type of Review: Revision of a currently approved collection.

Affected Public: Businesses or other for-profit organizations.

Estimated Number of Respondents: 37,200.

Estimated Time per Respondent: 4 hr., 20 min.

Estimated Total Annual Burden Hours: 161,448.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: August 2, 2011.

R. Joseph Durbala,

IRS Reports Clearance Officer.

[FR Doc. 2011–20381 Filed 8–10–11; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Agency Information Collection Activity; Proposed Collection

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)).

DATES: Written comments should be received on or before October 11, 2011 to be assured of consideration.

ADDRESSES: Direct all written comments to Yvette Lawrence, Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the regulations should be directed to R. Joseph Durbala at Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224, or at (202) 622–3634, or through the Internet at *RJoseph.Durbala@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Automatic Contribution Arrangements.

OMB Number: 1545–2135.

Regulation Project Number: REG–133300–07 (TD 9447—final).

Abstract: The proposed regulations provide guidance on how a qualified cash or deferred arrangement can become a qualified automatic contribution arrangement and avoid the ADP test of section 401(k)(3)(A)(ii). The proposed regulations also provide guidance on how an automatic contribution arrangement can permit an employee to make withdrawals from an eligible automatic contribution arrangement that he did not wish to have the employer make.

Current Actions: There is no change to this existing regulation.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organizations.

Estimated Number of Respondents: 30,000.

Estimated Time per Respondent: 60 minutes.

Estimated Total Annual Burden Hours: 30,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Comments are invited on:

(a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: August 3, 2011.

R. Joseph Durbala,

IRS Reports Clearance Officer.

[FR Doc. 2011–20382 Filed 8–10–11; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for the IRS Individual Taxpayer Burden Survey

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning the IRS Individual Taxpayer Burden Survey.

DATES: Written comments should be received on or before October 11, 2011 to be assured of consideration.

ADDRESSES: Direct all written comments to Yvette Lawrence, Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to R. Joseph Durbala, (202) 622–3634, at Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet at *RJoseph.Durbala@irs.gov*.

SUPPLEMENTARY INFORMATION:

Title: IRS Individual Taxpayer Burden Survey.

OMB Number: 1545–2212.

Form Number: CS–11–276.

Abstract: Conduct a survey of individual taxpayers in order to collect data on the burden (time and out-of-pocket expenses) that citizens spend in order to comply with tax laws and regulations. This information is needed in order to better understand the taxpayer burden and the drivers of taxpayer burden. This information will be used to produce estimates for the IRS' information collection budget as well as to support program evaluation and policy design.

Current Actions: There is no change in the paperwork burden previously approved by OMB. This form is being submitted for renewal purposes only.

Type of Review: Extension of a currently approved collection.

Affected Public: Businesses and other for-profit organizations.

Estimated Number of Respondents: 10,000.

Estimated Time per Respondent: 19 minutes.

Estimated Total Annual Burden Hours: 3,333.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: August 3, 2011.

Yvette Lawrence,

IRS Reports Clearance Officer.

[FR Doc. 2011–20383 Filed 8–10–11; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery.

DATES: Written comments should be received on or before October 11, 2011 to be assured of consideration.

ADDRESSES: Direct all written comments to Yvette Lawrence, Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to R. Joseph Durbala, (202) 622–3634, at Internal Revenue Service, Room 6129, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet at *RJoseph.Durbala@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery.

OMB Number: 1545–2208.

Abstract: Executive Order 12862 directs Federal agencies to provide service to the public that matches or exceeds the best service available in the private sector. In order to work continuously to ensure that our programs are effective and meet our customers' needs, The Internal Revenue Service (hereafter ''the Agency'') seeks to obtain OMB approval of a generic clearance to collect qualitative feedback on our service delivery. By qualitative feedback we mean information that provides useful insights on perceptions and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study.

Current Actions: We will be conducting different opinion surveys, focus group sessions, think-aloud interviews, and usability studies regarding cognitive research surrounding forms submission or IRS system/product development.

Type of Review: Revision of a currently approved collection.

Affected Public: Individuals and businesses or other for-profit organizations.

Estimated Number of Respondents: 150,000.

Estimated Time per Respondent: 60 minutes.

Estimated Total Annual Burden Hours: 150,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: August 3, 2011.

Yvette Lawrence,

IRS Reports Clearance Officer.

[FR Doc. 2011–20384 Filed 8–10–11; 8:45 am]

BILLING CODE 4830–01–P

FEDERAL REGISTER

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Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 35

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–23–000; Order No. 1000]

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. With respect to transmission planning, this Final Rule requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; removes from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

DATES: *Effective Date:* This final rule will become effective on October 11, 2011.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Order No. 1000

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I. Introduction

1. In this Final Rule, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms to its electric transmission planning and cost allocation requirements for public utility transmission providers.[1] The reforms herein are intended to improve

[1] 16 U.S.C. 824e (2006).

transmission planning processes and cost allocation mechanisms under the *pro forma* Open Access Transmission Tariff (OATT) to ensure that the rates, terms and conditions of service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential. This Final Rule builds on Order No. 890,[2] in which the Commission, among other things, reformed the *pro forma* OATT to require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. After careful review of the voluminous record in this proceeding, the Commission concludes that the additional reforms adopted herein are necessary at this time to ensure that rates for Commission-jurisdictional service are just and reasonable in light of changing conditions in the industry. In addition, the Commission believes that these reforms address opportunities for undue discrimination by public utility transmission providers.

2. The Commission acknowledges that significant work has been done in recent years to enhance regional transmission planning processes. The Commission appreciates the diversity of opinions expressed by commenters in response to the Notice of Proposed Rulemaking[3] as to whether, in light of the progress being made in many regions, further reforms to transmission planning processes and cost allocation mechanisms are necessary at this time. On balance, the Commission concludes that the reforms adopted herein are necessary for more efficient and cost-effective regional transmission planning. As discussed further below, the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost. The Commission concludes that it is appropriate to act now to ensure that its transmission planning processes and cost allocation requirements are adequate to allow public utility transmission providers to address these challenges more efficiently and cost-effectively. In reaching this conclusion, the Commission has balanced competing interests of various segments of the industry and designed a package of reforms that, in our view, will support the development of those transmission facilities identified by each transmission planning region as necessary to satisfy reliability standards, reduce congestion, and allow for consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations (Public Policy Requirements). By ''state or federal laws or regulations,'' we mean enacted statutes (*i.e.,* passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.

3. Through this Final Rule, we conclude that the existing requirements of Order No. 890 are inadequate. Public utility transmission providers are currently under no affirmative obligation to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective than solutions identified in local transmission planning processes. Similarly, there is no requirement that public utility transmission providers consider transmission needs at the local or regional level driven by Public Policy Requirements. Nonincumbent transmission developers seeking to invest in transmission can be discouraged from doing so as a result of federal rights of first refusal in tariffs and agreements subject to the Commission's jurisdiction. While neighboring transmission planning regions may coordinate evaluation of the reliability impacts of transmission within their respective regions, few procedures are in place for identifying and evaluating the benefits of alternative interregional transmission solutions. Finally, many cost allocation methods in place within transmission planning regions fail to account for the beneficiaries of new transmission facilities, while cost allocation methods for potential interregional facilities are largely nonexistent.

4. We correct these deficiencies by enhancing the obligations placed on public utility transmission providers in several specific ways. While focused on discrete aspects of the transmission planning and cost allocation processes, the specific reforms adopted in this Final Rule are intended to achieve two primary objectives: (1) Ensure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively; and (2) ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them. In addition, this Final Rule addresses interregional coordination and cost allocation, to achieve the same objectives with respect to possible transmission solutions that may be located in a neighboring transmission planning region.

5. Certain requirements of this Final Rule distinguish between ''a transmission facility in a regional transmission plan,'' and ''a transmission facility selected in a regional transmission plan for purposes of cost allocation.''[4] A ''transmission facility selected in a regional transmission plan for purposes of cost allocation'' is one that has been selected, pursuant to a Commission-approved regional transmission planning process, as a more efficient or cost-effective solution to regional transmission needs. As discussed in more detail below, this distinction is an essential component of this Final Rule.

6. Turning to the specific discrete reforms we adopt today, we first require public utility transmission providers to participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. This requirement builds on the transmission planning principles adopted by the Commission in Order No. 890, and the regional transmission planning processes developed in response to this Final Rule must satisfy those principles. These processes must result in the development of a regional transmission plan. As part of our reforms, we also require that the regional transmission planning process, as well as the underlying local transmission planning processes of public utility transmission providers, provide an opportunity to consider transmission needs driven by Public Policy Requirements. We conclude that requiring each local and regional transmission planning process to provide this opportunity is necessary to ensure that transmission planning processes identify and evaluate transmission needs driven by relevant

[2] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification,* Order No. 890–B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[3] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,660 (2010) (Proposed Rule).

[4] *See infra* P 0.

Public Policy Requirements, and support more efficient and cost-effective achievement of those requirements.

7. Second, we direct public utility transmission providers to remove from their OATTs or other Commission-jurisdictional tariffs and agreements any provisions that grant a federal right of first refusal to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation.[5] We conclude that leaving federal rights of first refusal in place for these facilities would allow practices that have the potential to undermine the identification and evaluation of a more efficient or cost-effective solution to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers. To implement the elimination of such federal rights of first refusal, we adopt below a framework that requires, among other things, the development of qualification criteria and protocols for the submission and evaluation of transmission proposals. In addition, as described in section III.B.3, we also require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations. This requirement, however, applies only to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation and not, for example, to transmission facilities in local transmission plans that are merely ''rolled up'' and listed in a regional transmission plan without going through an analysis at the regional level, and therefore, not eligible for regional cost allocation.

8. Third, we require public utility transmission providers to improve coordination across regional transmission planning processes by developing and implementing, through their respective regional transmission planning process, procedures for joint evaluation and sharing of information regarding the respective transmission needs of transmission planning regions and potential solutions to those needs. These procedures must provide for the identification and joint evaluation by neighboring transmission planning regions of interregional transmission facilities to determine if there are more efficient or cost-effective interregional transmission solutions than regional solutions identified by the neighboring transmission planning regions. To facilitate the joint evaluation of interregional transmission facilities, we require the exchange of planning data and information between neighboring transmission planning regions at least annually.

9. Finally, we require public utility transmission providers to have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. We also require public utility transmission providers in each transmission planning region to have, together with the public utility transmission providers in a neighboring transmission planning region, a common method, or set of methods, for allocating the costs of a new interregional transmission facility that is jointly evaluated by the two or more transmission planning regions in their interregional transmission coordination procedures. Given the fact that a determination by the transmission planning process to select a transmission facility in a plan for purposes of cost allocation will necessarily include an evaluation of the benefits of that facility, we require that transmission planning and cost allocation processes be aligned. Further, all regional and interregional cost allocation methods must be consistent with regional and interregional cost allocation principles, respectively, adopted in this Final Rule. Nothing in this Final Rule requires either interconnectionwide planning or interconnectionwide cost allocation.

10. The cost allocation reforms adopted today, and the cost allocation principles that each proposed regional and interregional cost allocation method or methods must satisfy, seek to address the potential opportunity for free ridership inherent in transmission services, given the nature of power flows over an interconnected transmission system. In particular, the principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits.[6] In addition, the Commission finds that participant funding is permitted, but not as a regional or interregional cost allocation method.

11. As noted above, the various specific reforms adopted in this Final Rule are designed to work together to ensure an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that those transmission facilities selected in a regional transmission plan for purposes of cost allocation are the more efficient or cost-effective solutions available. At its core, the set of reforms adopted in this Final Rule require the public utility transmission providers in a transmission planning region, in consultation with their stakeholders, to create a regional transmission plan. This plan will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability, economic and Public Policy Requirements. To meet such requirements more efficiently and cost-effectively, the regional transmission plan must reflect a fair consideration of transmission facilities proposed by nonincumbents, as well as interregional transmission facilities. The regional transmission plan must also include a clear cost allocation method or methods that identify beneficiaries for each of the transmission facilities selected in a regional transmission plan for purposes of cost allocation, in order to increase the likelihood that such transmission facilities will actually be constructed.

12. The transmission planning and cost allocation requirements in this Final Rule, like those of Order No. 890, are focused on the transmission planning *process,* and not on any substantive outcomes that may result from this process. Taken together, the requirements imposed in this Final Rule work together to remedy deficiencies in the existing requirements of Order No. 890 and enhance the ability of the transmission grid to support wholesale power markets. This, in turn, will fulfill our statutory obligation to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.

13. We acknowledge that public utility transmission providers in some

[5] *See infra* P 0.

[6] However, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead rely on participant funding. *See infra* P 723–729.

transmission planning regions already may have in place transmission planning processes or cost allocation mechanisms that satisfy some or all of the requirements of this Final Rule. Our reforms are not intended to undermine progress being made in those regions, nor do we intend to undermine other planning activities that are being undertaken at the interconnection level. Rather, the Commission is acting here to identify a minimum set of requirements that must be met to ensure that all transmission planning processes and cost allocation mechanisms subject to its jurisdiction result in Commission-jurisdictional services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

14. The Commission appreciates the significant work that will go into the preparation of compliance proposals in response to this Final Rule. To assist public utility transmission providers in their efforts to comply, the Commission directs its staff to hold informational conferences within 60 days of the effective date of this Final Rule to review and discuss the requirements imposed herein with interested parties. Moreover, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

A. Order Nos. 888 and 890

15. In Order No. 888,[7] issued in 1996, the Commission found that it was in the economic interest of transmission providers to deny transmission service or to offer transmission service to others on a basis that is inferior to that which they provide to themselves.[8] Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 and the accompanying *pro forma* OATT implemented open access to transmission facilities owned, operated, or controlled by a public utility.

16. As part of those reforms, Order No. 888 and the *pro forma* OATT set forth certain minimum requirements for transmission planning. For example, the *pro forma* OATT required a public utility transmission provider to account for the needs of its network customers in its transmission planning activities on the same basis as it provides for its own needs.[9] The *pro forma* OATT also required that new facilities be constructed to meet the transmission service requests of long-term firm point-to-point customers.[10] While Order No. 888–A went on to encourage utilities to engage in joint and regional transmission planning with other utilities and customers, it did not require those actions.[11]

17. In early 2007, the Commission issued Order No. 890 to remedy flaws in the *pro forma* OATT that the Commission identified based on the decade of experience since the issuance of Order No. 888. Among other things, the Commission found that *pro forma* OATT obligations related to transmission planning were insufficient to eliminate opportunities for undue discrimination in the provision of transmission service. The Commission stated that particularly in an era of increasing transmission congestion and the need for significant new transmission investment, it could not rely on the self-interest of transmission providers to expand the grid in a not unduly discriminatory manner. Among other shortcomings in the *pro forma* OATT, the Commission pointed to the lack of clear criteria regarding the transmission provider's planning obligation; the absence of a requirement that the overall transmission planning process be open to customers, competitors, and state commissions; and the absence of a requirement that key assumptions and data underlying transmission plans be made available to customers.

18. In light of these findings, one of the primary goals of the reforms undertaken in Order No. 890 was to address the lack of specificity regarding how stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in transmission planning activities, the Commission required each public utility transmission provider to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to its OATT (Attachment K). The Order No. 890 transmission planning principles are: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[12]

19. The transmission planning reforms adopted in Order No. 890 apply to all public utility transmission providers, including Commission-approved RTOs and ISOs. The Commission stated that it expected all non-public utility transmission providers to participate in the local transmission planning processes required by Order No. 890, and that reciprocity dictates that non-public utility transmission providers that take advantage of open access due to improved planning should be subject to the same requirements as public utility transmission providers.[13] The Commission stated that a coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. However, the Commission did not invoke its authority under FPA section 211A, which allows the Commission to require an unregulated transmitting utility (*i.e.,* a non-public utility transmission provider) to provide transmission services on a comparable and not unduly discriminatory or preferential basis.[14] The Commission instead stated that if it found, on the appropriate record, that non-public utility transmission providers are not participating in the transmission planning processes required by Order No. 890, then the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

20. On December 7, 2007, pursuant to Order No. 890, most public utility transmission providers and several non-public utility transmission providers submitted compliance filings that describe their proposed transmission

[7] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (DC Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[8] Order No. 888, FERC Stats. & Regs. at 31,682.

[9] *See* Section 28.2 of the *pro forma* OATT.

[10] *See* Sections 13.5, 15.4, and 27 of the *pro forma* OATT.

[11] Order No. 888–A, FERC Stats. & Regs. at 30,311.

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418–601.

[13] *Id.* P 441.

[14] FPA section 211A(b) provides, in pertinent part, that ''the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services—(1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' 16 U.S.C. 824j.

planning processes.[15] The Commission addressed these filings in a series of orders that were issued throughout 2008. Generally, the Commission accepted the compliance filings to be effective on December 7, 2007, subject to further compliance filings as necessary for the proposed transmission planning processes to satisfy the nine Order No. 890 transmission planning principles. The Commission issued additional orders on Order No. 890 transmission planning compliance filings in the spring and summer of 2009.

21. As a result of these compliance filings, regional transmission organization (RTO) and independent system operators (ISO) have enhanced their regional transmission planning processes, making them more open, transparent, and inclusive. Regions of the country outside of RTO and ISO regions also have made significant strides with respect to transmission planning by working together to enhance existing, or create new, regional transmission planning processes.[16] These improvements to transmission planning processes have given stakeholders the ability to participate in the identification of regional transmission needs and corresponding solutions, thereby facilitating the development of more efficient and cost-effective transmission expansion plans. This Final Rule expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission's ongoing monitoring of these matters.

B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation

22. In several of the above-noted orders issued in 2008 and early 2009 on filings submitted to comply with the Order No. 890 transmission planning requirements, the Commission stated that it would continue to monitor implementation of these transmission planning processes. The Commission also announced its intention to convene regional technical conferences in 2009.

23. Consistent with the Commission's announcement, Commission staff in September 2009 convened three regional technical conferences in Philadelphia, Atlanta, and Phoenix, respectively. The focus of the technical conferences was to: (1) Determine the progress and benefits realized by each transmission provider's transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement; (2) examine whether existing transmission planning processes adequately consider needs and solutions on a regional or interconnectionwide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) explore whether existing transmission planning processes are sufficient to meet emerging challenges to the transmission system, such as the development of interregional transmission facilities and the integration of large amounts of location-constrained generation. Issues discussed at the technical conferences included the effectiveness of the current transmission planning processes, the development of regional and interregional transmission plans, and the effectiveness of existing cost allocation methods used by transmission providers and alternatives to those methods.

24. Following these technical conferences, the Commission in October 2009 issued a Notice of Request for Comments.[17] The October 2009 Notice presented numerous questions with respect to enhancing regional transmission planning processes and allocating the cost of transmission. In response to the October 2009 Notice, the Commission received 107 initial comments and 45 reply comments.

C. Additional Developments Since Issuance of Order No. 890

25. Other developments with important implications for transmission planning have occurred amid the above-noted Order No. 890 compliance efforts on transmission planning and as the Commission gathered information through the technical conferences and the October 2009 Notice discussed above.

26. For example, in February 2009, Congress enacted the American Recovery and Reinvestment Act (ARRA), which provided $80 million for the U.S. Department of Energy (DOE), in coordination with the Commission, to support the development of interconnection-based transmission plans for the Eastern, Western, and Texas interconnections. In seeking applications for use of those funds, DOE described the initiative as intended to: Improve coordination between electric industry participants and states on the regional, interregional, and interconnectionwide levels with regard to long-term electricity policy and planning; provide better quality information for industry planners and state and federal policymakers and regulators, including a portfolio of potential future supply scenarios and their corresponding transmission requirements; increase awareness of required long-term transmission investments under various scenarios, which may encourage parties to resolve cost allocation and siting issues; and facilitate and accelerate development of renewable energy or other low-carbon generation resources.[18]

27. In December 2009, DOE announced award selections for much of this ARRA funding. In each interconnection, applicants awarded funds under what DOE defined as Topic A are responsible for conducting interconnection-level analysis and transmission planning. Applicants awarded funds under Topic B are to facilitate greater cooperation among states within each interconnection to guide the analyses and planning performed under Topic A.[19] Broad participation in sessions to date related to this initiative suggest that the availability of federal funds to pursue these goals has increased awareness of the potential for greater coordination among regions in transmission planning.

28. In describing the activities undertaken under this transmission analysis and planning initiative, DOE staff leading the project has explained that its activities are based on the premise that the electricity industry faces a major long-term challenge in ensuring an adequate, affordable and environmentally sensitive energy supply and that an open, transparent, inclusive, and collaborative process for transmission planning is essential to securing this energy supply.[20] To that end, DOE staff has stressed that all stakeholders need to be involved in

[15] A small number of public utility transmission providers were granted extensions.

[16] The regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are the North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.

[17] Federal Energy Regulatory Commission, Notice of Request for Comments, Transmission Planning Processes under Order No. 890; Docket No. AD09–8–000, October 8, 2009 (October 2009 Notice).

[18] Department of Energy, *Recovery Act—Resource Assessment and Interconnection-Level Transmission Analysis and Planning Funding Opportunity Announcement,* at 5–6 (June 15, 2009).

[19] *Id.* at 4–8.

[20] Department of Energy, ''*DOE Initiative Regarding Interconnection-Level Transmission Analysis and Planning;*'' presented at the NGA Transmission Roundtable by David Meyer of DOE's Office of Electricity Delivery and Energy Reliability, January 25, 2011.

assessing options to meeting this future need and that ARRA funds are ''seed money'' to help establish capabilities to address transmission planning issues.[21] In DOE staff's view, the goal of this funding is to help planners develop a portfolio of long-term energy supply and demand for future needs and associated transmission requirements to assess the implications of these alternative future energy scenarios and identify facilities appropriate for consideration in the development of long-term infrastructure plans. Key deliverables of the DOE-funded planning activities are 10- and 20-year plans that analyze the transmission needs of each interconnection under a range of scenarios.

29. While the results of these planning efforts are not yet available, there is already a growing body of evidence that, in DOE's words, ''[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario.'' [22] In its most recent Long-Term Reliability Assessment, North American Electric Reliability Corporation (NERC) identifies 39,000 circuit-miles of projected high-voltage transmission over the next 10 years.[23] NERC estimates that roughly a third of these transmission facilities will be needed to integrate variable and renewable generation.[24] Much of this investment in renewable generation is being driven by renewable portfolio standards adopted by states. Some 28 states and the District of Columbia have now adopted renewable portfolio standard measures. In addition, there are 9 states with non-binding goals. The key difference is that the states with requirements usually have financial penalties for non-compliance, known as alternative compliance payments. States with non-binding goals usually have no financial penalty, although some have instituted financial incentives for meeting the goal (*e.g.,* Virginia). These measures typically require that a certain percentage of energy sales (MWh) or installed capacity (MW) come from renewable energy resources, with the target level and qualifying resources varying among the renewable portfolio standard measures. Most of these portfolio standards are set to increase annually, further amplifying the potential need for transmission facilities.

[21] *Id.*

[22] Department of Energy, *20% Wind Energy by 2030,* at 93 (July 2008).

[23] NERC 2010 Assessment at 22.

[24] *Id.* at 24.

II. The Need for Reform

A. Proposed Rule

30. In light of the changes occurring within the electric industry, and based on the Commission's experience in implementing Order No. 890 and comments submitted in response to the October 2009 Notice, the Commission issued the Proposed Rule on June 17, 2010 identifying further reforms to the *pro forma* OATT in the areas of transmission planning and cost allocation. These reforms, discussed in detail below, were aimed at ensuring that the transmission planning and cost allocation requirements established in Order No. 890 continue to result in the provision of Commission-jurisdictional service at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. The Commission received roughly 5,700 pages of initial and reply comments in response. Based on these comments, the Commission concludes that amendment of the transmission planning and cost allocation requirements established in Order No. 890 is necessary at this time to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

31. The Commission noted in the Proposed Rule that transmission planning processes, particularly at the regional level, have seen substantial improvement through compliance with Order No. 890. However, the Commission explained that changes in the nation's electric power industry since issuance of Order No. 890 required the Commission to consider additional reforms to transmission planning and cost allocation to reflect these new circumstances. The Commission stated its intention was not to disrupt the progress being made with respect to transmission planning and investment in transmission infrastructure, but rather to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

B. Comments

32. A number of commenters generally support the Commission's decision to initiate a rulemaking proceeding that proposes reforms to the transmission planning and cost allocation processes.[25] Several of these commenters state that inadequate transmission planning and cost allocation processes have impeded the development of transmission infrastructure.[26]

33. For example, Transmission Dependent Utility Systems state that they support the primary objective of the Proposed Rule to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale markets and ensure that jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. Exelon argues that the current system of disconnected priorities and mixed criteria is simply not working. Pennsylvania PUC encourages the Commission to eliminate the current uncertainty regarding planning and paying for future transmission expansion and upgrades.

34. MidAmerican adds that transmission has grown from an industry sector focused on rebuilds, reliability improvements on existing infrastructure, and construction of generation-dependent interconnection facilities, to one where new and upgraded transmission infrastructure is necessary to effectuate the expansion of regional power markets, promote a more reliable transmission system, accommodate increasing reliance on renewable generation sources, and address the uncertainty of the future role of existing conventional generation. AWEA contends that existing processes for planning and paying for transmission are not sufficient to meet the emerging challenges to the transmission system. AWEA argues that many cost allocation methodologies, as they are applied today, are flawed, which together with the fragmented and short-term transmission planning regimes prevalent today, have often

[25] *E.g.,* 26 Public Interest Organizations; AEP; American Transmission; AWEA; Anbaric and PowerBridge; Atlantic Grid; Colorado Independent Energy Association; Conservation Law Foundation; Duke; East Texas Cooperatives; Energy Future Coalition; Exelon; Gaelectric; Green Energy Express and 21st Century; Iberdrola Renewables; Imperial Irrigation District; Integrys; ISO New England; ITC Companies; MidAmerican; Multiparty Commenters; National Audubon Society; National Grid; New York ISO; New York PSC; NextEra; Northwest & Intermountain Power Producers Coalition; Old Dominion Electric Cooperative; Pennsylvania PUC; Ignacio Perez-Arriaga; Senators Dorgan and Reid; SPP; Transmission Access Policy Study Group; Transmission Dependent Utility Systems; Western Grid Group; Wind Coalition; WIRES; and Wisconsin Electric.

[26] *E.g.,* AEP; AWEA; Exelon; Iberdrola Renewables; ITC Companies; MidAmerican; and NextEra.

stifled investment in, or otherwise led to the inefficient use and inadequate expansion of the nation's transmission network. Senators Dorgan and Reid state that better coordination of regional transmission planning and clarifying cost allocation are two important steps in overcoming hurdles to developing the nation's vast renewable energy resources and providing clean energy jobs. National Grid contends that the creation of a robust transmission system is imperative to achieving important policy goals, environmental objectives, market efficiencies, and the integration of renewable and distributed resources into electric power markets.

35. NextEra agrees on reply that there is a need for generic reform at this time, stating that there is a sufficient basis for the Commission to proceed with a rulemaking proceeding and that there is ample evidence of the pressing need to enhance the transmission grid. NextEra states that the Proposed Rule demonstrates how and why existing transmission planning and cost allocation rules are inadequate.

36. A number of commenters provide specific examples of developments that further demonstrate the need for reform. Colorado Independent Energy Association states that, in WestConnect, regional transmission providers are not ignoring the problem of transmission constraints, but that development of transmission facilities is not being undertaken and, second, transmission facilities are not being properly sized. In its view, the problems can be traced to the absence of cost allocation methods or the lack of means for identifying the most needed projects and pursuing them to completion.

37. Iberdrola Renewables contends that the lack of transmission expansion in the MISO has led to significant congestion in areas with extensive operating wind generation. It states that the MISO has reported that wind curtailments primarily caused by congestion averaged five percent for the first six months of 2010 compared with 2 percent on average in 2009. Exelon adds that the lack of coordination between the MISO and PJM transmission planning regions has resulted in a significant increase in the out-of-merit dispatch of generation on the Commonwealth Edison system to maintain NERC reliability requirements. Exelon states that these events have increased from 31 in 2006 to 280 in 2009, and they result in higher costs on the system and excessive wear and tear on equipment.

38. Brattle Group states that it has identified approximately 130 mostly conceptual and often overlapping planned transmission projects throughout the country with a total cost of over $180 billion.[27] It contends that a large portion of these projects will not be built due to overlaps and deficiencies in transmission planning and cost allocation processes. Brattle Group states that many of the benefits associated with economic and public policy projects are difficult to quantify and, without changes to transmission planning and cost allocation processes, many of these projects may fail to gain the needed support for approval, permitting, and cost recovery.

39. Other commenters question the need for Commission action at this time, urging the Commission to be more rigorous in its proposed findings and holdings and arguing that the Proposed Rule is not supported by substantial evidence.[28] Large Public Power Council disagrees with the Commission's assertions in the Proposed Rule that state that renewable portfolio standards have contributed to the need for new transmission. Large Public Power Council states that the Commission offers no factual evidence to support its assertions [29] and that the evidence available actually weighs against the Commission. Large Public Power Council states that renewable portfolio standards have not increased meaningfully since the Commission issued Order No. 890. Furthermore, Large Public Power Council cites a report produced by Edison Electric Institute that states that the members of Edison Electric Institute are making significant and growing investments in transmission infrastructure, including interstate projects and projects that will facilitate the integration of renewable resources. Moreover, Large Public Power Council contends that the Commission offers no evidence that the reforms of the type proposed are a necessary or satisfactory solution to the perceived problem.

40. Replying to commenters that stress the need for reform, discussed above, several commenters argue that none provides evidence supporting the need for a nationwide rule at this time.[30] Ad Hoc Coalition of Southeastern Utilities states that commenters such as Exelon and Multiparty Commenters provide only anecdotes supporting their contention that there is a need to reform transmission planning and cost allocation processes, and argues that these individual issues can be addressed on a case-specific basis rather than through generic rules. Joined by Southern Companies, Ad Hoc Coalition of Southeastern Utilities argues that factual allegations of transmission expansion deficiencies are not applicable to the Southeast, pointing to their robust transmission grid. They state that, to the extent these allegations raise issues for other regions, then they should be addressed within those regions and that these issues do not merit nationwide treatment.[31] Additionally, Ad Hoc Coalition of Southeastern Utilities asserts that existing planning processes under Order No. 890 have not been in place long enough to determine whether reforms are needed, and other commenters assert that existing planning processes are working well.[32] PSEG Companies assert that the real issue is the siting process, which makes it difficult to actually build projects even if they are truly needed to maintain system reliability.

41. Indianapolis Power & Light states that the Commission has not undertaken any type of analysis to find out what needs to be built, where it needs to be built, and who needs to build it. Indianapolis Power & Light asserts that the Commission has not looked closely at the different regions of the country to determine which areas could benefit from the new proposed reforms. Indianapolis Power & Light states that the Commission has not sufficiently demonstrated a need for this rulemaking and should consider whether its broad-based application is necessary in the first place. San Diego Gas & Electric recommends that the Commission not issue a Final Rule at this time, arguing

[27] Brattle Group, Attachment at 5.

[28] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Salt River Project; Large Public Power Council (each commenter cites *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831 (DC Cir. 2006) (*National Fuel*)); Large Public Power Council (citing *Associated Gas Distrib.* v. *FERC,* 824 F.2d 981 (DC Cir. 1985) (*Associated Gas Distributors*)); PSEG Companies; Salt River Project; and San Diego Gas & Electric.

[29] Citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 148–154 (Large Public Power Council cites to the following two assertions in the Proposed Rule: ''Further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions.'' (Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 150); and ''* * * the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities across several utility and/or RTO or ISO regions.'' (Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 151)).

[30] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; San Diego Gas & Electric; and Southern Companies.

[31] Ad Hoc Coalition of Southeastern Utilities, Large Public Power Council and Southern Companies cite to *Associated Gas Distributors,* 824 F.2d 981 at 1019.

[32] *E.g.,* PSEG Companies and Salt River Project.

that doing so based on the current proposals would disrupt and delay the build-out of the transmission grid and cause transmission providers to redirect resources away from that primary objective to the inevitable legal and compliance challenges to this Final Rule.

C. Commission Determination

42. The Commission concludes that it is appropriate to act at this time to adopt the package of reforms contained in this Final Rule. Our review of the record, as well as the recent studies discussed above, indicates that the transmission planning and cost allocation requirements established in Order No. 890 provide an inadequate foundation for public utility transmission providers to address the challenges they are currently facing or will face in the near future. Although focused on discrete aspects of transmission planning and cost allocation processes, the reforms adopted in this Final Rule are designed to work together to ensure an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that transmission facilities in the transmission plan will move forward to construction. The Commission's actions today therefore will enhance the ability of the transmission grid to support wholesale power markets and, in turn, ensure that Commission-jurisdictional transmission services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential.

43. The Commission acknowledges that transmission planning processes have seen substantial improvements, particularly at the regional level, in the relatively short time since the issuance of Order No. 890. Moreover, as some commenters note, transmission planning processes in many regions continue to evolve as public utility transmission providers and stakeholders explore new ways of addressing mutual needs. However, the Commission is concerned that the existing requirements of Order No. 890 regarding transmission planning and cost allocation are insufficient to ensure that this evolution will occur in a manner that ensures that the rates, terms and conditions of service by public utility transmission providers are just and reasonable and not unduly discriminatory. As a number of commenters contend, inadequate transmission planning and cost allocation requirements may be impeding the development of beneficial transmission lines or resulting in inefficient and overlapping transmission development due to a lack of coordination, all of which contributes to unnecessary congestion and difficulties in obtaining more efficient or cost-effective transmission service.

44. The increase in transmission investment in recent years, as noted in the report produced by Edison Electric Institute and cited by Large Public Power Council,[33] does not mitigate our need to act at this time. To the contrary, as discussed below, the recent increase in transmission investment supports issuance of this Final Rule to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions moving forward. In its report, Edison Electric Institute states that its members have steadily increased investment in transmission over the period from 2001 to 2009, resulting in approximately $55.3 billion in new transmission facilities.[34] NERC confirms the recent increase in investment in its 2010 Long-Term Reliability Assessment.[35] This trend appears to be only the beginning of a longer-term period of investment in new transmission facilities. In another report commissioned by Edison Electric Institute, Brattle Group suggests that approximately $298 billion of new transmission facilities will be required over the period from 2010 to 2030.[36] NERC's analysis of the past 15 years of transmission development confirms the significant increase in future transmission investment, showing that additional transmission planned for construction during the next five years nearly triples the average miles that have historically been constructed.[37]

45. The need for additional transmission facilities is being driven, in large part, by changes in the generation mix. As NERC notes in its 2009 Assessment, existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the mix of generation resources, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable generation.[38] NERC has identified approximately 131,000 megawatts of new generation planned for construction over the next ten years, with the largest fuel-type growth in gas-fired and wind generation resources.[39] These shifts in the generation fleet increase the need for new transmission. Additionally, the existing transmission system was not built to accommodate this shifting generation fleet. Of the total miles of bulk power transmission under construction, planned, and in a conceptual stage, NERC estimates that 50 percent will be needed strictly for reliability and an additional 27 percent will be needed to integrate variable and renewable generation across North America.[40]

46. Rather than demonstrating a lack of need for action, as claimed by some commenters, the recent increases in constructed and planned transmission facilities supports issuance of this Final Rule at this time to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions. The increased focus on investment in new transmission projects makes it even more critical to implement these reforms to ensure that the more efficient or cost-effective projects come to fruition. The record in this proceeding and the reports cited above confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges.

47. As explained below, each of the individual reforms adopted by the Commission is intended to address specific deficiencies in the Commission's existing transmission planning and cost allocation requirements. Through this package of reforms, the Commission seeks to ensure that each public utility transmission provider will work within its transmission planning region to create a regional transmission plan that identifies transmission facilities needed to meet reliability, economic and Public Policy Requirements, including fair

[33] Large Public Power Council (citing *Edison Electric Institute report, available at http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf*).

[34] Edison Electric Institute at v.

[35] NERC 2010 Assessment at 25; *see also* Brattle Group, Attachment at 4 (noting rapid increase in transmission development, from $2 billion annually in the 1990s to $8 billion annual in 2008 and 2009).

[36] Transforming America's Power Industry at 37, *http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf.*

[37] NERC 2010 Long-Term Reliability Assessment at 25.

[38] NERC 2009 Long-Term Reliability Assessment at 8; *see also supra* P 29 (summarizing current state renewable portfolio standards).

[39] NERC 2010 Long-Term Reliability Assessment at 12.

[40] *Id.* at 24.

consideration of lines proposed by nonincumbents, with cost allocation mechanisms in place to facilitate lines moving from planning to development. Although focused on particular aspects of the Commission's transmission planning and cost allocation requirements, these reforms are integrally related and should be understood as a package that is designed to reform processes and procedures that, if left in place, could result in Commission-jurisdictional services being provided at rates that are unjust and unreasonable and unduly discriminatory or preferential.

48. A number of commenters maintain that the Commission in the Proposed Rule failed to provide adequate evidence to support a finding under section 206 of the FPA that the reforms adopted in this Final Rule are necessary to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Section 313(b) of the FPA makes Commission findings of fact conclusive if they are supported by substantial evidence.[41] When applied in a rulemaking context, "the substantial evidence test is identical to the familiar arbitrary and capricious standard." [42] The Commission thus must show that a "reasonable mind might accept" that the evidentiary record here is "adequate to support a conclusion," [43] in this case that this Final Rule is needed "to correct deficiencies in transmission planning and cost allocation processes," as described.[44] In the legal authority sections throughout this Final Rule, the Commission discusses how the cases cited by commenters demonstrate that the Commission has met its burden.

49. Commenters that maintain that the Commission's proposal is not supported by substantial evidence demand that the Commission identify evidence that is far in excess of what a reasonable person would require. We thus disagree with such comments, including Indianapolis Power & Light's, that it is necessary for the Commission to determine what needs to be built, where it needs to be built, and who needs to build it. That is not, and is not required to be, the intent of this rulemaking. This rulemaking reforms processes and is not intended to address such questions. No commenter has contested the need for additional transmission facilities, and numerous examples have been provided here of transmission planning and cost allocation impediments to the development of such facilities. Our intent here is to continue to ensure that public utility transmission providers use just and reasonable transmission planning processes and procedures, as required by Order Nos. 888 and 890, to provide for the needs of their transmission customers. Such planning may require public utility transmission providers—in consultation with stakeholders—to determine what needs to be built, where it needs to be built, and who needs to build it, but the Commission is not making such determinations here.

50. We also reject the characterization of factual examples presented to demonstrate the need for reform as anecdotal evidence. A wide range of concerns have been raised by commenters, and the Commission need not, and should not, wait for systemic problems to undermine transmission planning before it acts. The Commission must act promptly to establish the rules and processes necessary to allow public utility transmission providers to ensure planning of and investment in the right transmission facilities as the industry moves forward to address the many challenges it faces. Transmission planning is a complex process that requires consideration of a broad range of factors and an assessment of their significance over a period that can extend from present out to 20, 30 years or more in the future. In addition, the development of transmission facilities can involve long lead times and complex problems related to design, siting, permitting, and financing. Given the need to deal with these matters over a long time horizon, it is appropriate and prudent that we act at this time rather than allowing the types of problems described above to continue or to increase. In light of these conditions and as explained below, we find that it is reasonable to take generic action through this rulemaking proceeding.

51. A brief consideration of the two cases that commenters rely on to argue that the Commission has not satisfied the substantial evidence standard helps to demonstrate that the standard has been fully met. In *National Fuel,* the court found that the Commission had not met the substantial evidence standard when it sought to extend its standards of conduct that regulate natural gas pipelines' interactions with their marketing affiliates to their interactions with their non-marketing affiliates. The court noted that it had upheld the standards of conduct as applied to pipelines and their marketing affiliates because the Commission had shown both a theoretical threat that pipelines could grant undue preferences to their marketing affiliates and evidence that such abuse had occurred.[45] In finding that the Commission had not met the substantial evidence standard when seeking to extend the standards of conduct, the court noted that the Commission had not cited a single example of abuse by non-marketing affiliates. It concluded that the Commission relied either on examples of abuse or comments from the rulemaking that simply reiterated a theoretical potential for abuse.[46] The court remanded the matter and noted that if the Commission chose to proceed it could even rely solely on a theoretical threat if it could show how the threat justified the costs that the rules would create.[47]

52. Our action in this Final Rule is entirely consistent with the standards that the court set forth in *National Fuel.* We conclude that the narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities, and that addressing these issues is necessary to ensure just and reasonable rates. In other words, the problem that the Commission seeks to resolve represents a "theoretical threat," in the words of the *National Fuel* decision, the features of which are discussed throughout the body of this Final Rule in the context of each of the reforms adopted here. This threat is significant enough to justify the requirement imposed by this Final Rule. It is not one that can be addressed adequately or efficiently through the adjudication of individual complaints. The problems that we seek to resolve here stem from the absence of planning processes that take a sufficiently broad view of both the tasks involved and the means of addressing them. Individual adjudications by their nature focus on discrete questions of a specific case. Rules setting forth general principles are necessary to ensure that adequate planning processes are in place.

53. Stated in another way, in the terminology of *National Fuel,* the remedy we adopt is justified sufficiently by the "theoretical threat" identified herein, even without "record evidence of abuse." The actual experiences of problems cited in the record herein provide additional support for our

[41] 16 U.S.C. 825l(b).

[42] *Wisconsin Gas Co.* v. *FERC,* 770 F.2d 1144, 1156 (1985); *see also Associated Gas Distributors* v. *FERC,* 824 F.2d 981 at 1018.

[43] *Dickenson* v. *Zurko,* 527 U.S. 150, 155 (1999).

[44] Proposed Rule, FERC Stats & Regs. ¶ 32,660 at P 1.

[45] *National Fuel,* 468 F.3d 831 at 839.

[46] *Id.* at 841.

[47] *Id.* at 844.

action, but are not necessary to justify the remedy.

54. *Associated Gas Distributors* likewise is distinguishable from this proceeding. In that case, the court reviewed the Commission's rationale in Order No. 436 for industry-wide contract demand adjustment conditions, which permitted pipeline customers to reduce their contract demand by up to 100 percent over a period of five years.[48] The court held that the Commission failed to develop an adequate rationale for authorizing what it characterized as the ''drastic action'' of 100 percent contract demand reduction, and that the reasons the Commission provided ''seem[ed] peripheral to the problem the Commission set out to solve.'' [49] The court also found that one of the Commission's arguments while ''highly relevant'' to contract demand reduction, failed to support the broad remedy the Commission adopted.[50] The court explained that it was unclear why an industry-wide solution was necessary to solve a problem that the Commission suggested applied only ''to a limited portion of the industry.'' [51]

55. We find that the facts and findings of *Associated Gas Distributors* are in no way comparable to the matters involved in this Final Rule. We disagree with commenters that characterize our reasoning as inadequate or peripheral to the problems that the Commission has identified in this proceeding. To the contrary, the reforms adopted herein are necessary to address those problems and are supported by the reasons set forth in this Final Rule. As discussed herein, the Commission finds that the narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities. There is a close relationship between those problems and the Commission's actions here to identify a minimum set of requirements that must be met to ensure that transmission planning processes and cost allocation methods subject to its jurisdiction result in Commission-jurisdictional services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

56. We also disagree with commenters that argue that the reforms adopted in this Final Rule will have an impact on industry that is comparable to the impact at issue in *Associated Gas Distributors.* The impact in that case involved the potential losses a gas pipeline could face from 100 percent contract demand reduction by a customer over a period of five years. Such reduction represents the complete elimination of expected revenues from gas sales under a contract. By contrast, compliance with this Final Rule will involve the adoption and implementation of additional processes and procedures. Many public utility transmission providers that are subject to this Final Rule already engage in processes and procedures of this type.

57. We acknowledge that some public utility transmission providers may need to do more than others to achieve compliance with the requirements of this Final Rule. Such differences, however, do not mean that the problems identified herein are ''limited to a portion of the industry,'' in the terms used in *Associated Gas Distributors.* Indeed, acting on a generic basis is necessary for the Commission to identify and implement a minimum set of requirements for transmission planning processes and cost allocation methods, as discussed above.

58. We also disagree with commenters who assert that the Commission is relying on unsubstantiated allegations of discriminatory conduct or that the current Order No. 890 processes have not been in place long enough to justify the reforms proposed herein. The courts have made clear that the Commission need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination.[52] In *Associated Gas Distributors,* the court explained that the promulgation of generic rate criteria involves the determination of policy goals and the selection of the means to achieve them and that courts do not insist on empirical data for every proposition upon which the selection depends: ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [53] As discussed in this Final Rule, the Commission has received many comments arguing that commenters have experienced unjust and unreasonable, or unduly discriminatory or preferential practices in the transmission planning aspects of the transmission service provided by public utility transmission providers and that the lack of guidance from the Commission has delayed, as well as hindered, transmission projects. We have an obligation under section 206 to remedy these unjust and unreasonable, or unduly discriminatory or preferential rates, terms, and conditions and practices affecting rates.

59. It is thus clear to us that, notwithstanding the Commission's efforts in Order No. 890, deficiencies in the requirements of the existing *pro forma* OATT must be remedied to support the more efficient and cost-effective development of transmission facilities used to provide Commission-jurisdictional services. Moreover, action is needed to address the opportunities to engage in undue discrimination by public utility transmission providers. Our actions in this Final Rule are necessary to produce rates, terms and conditions that are just and reasonable. We therefore exercise our broad remedial authority [54] today to ensure that rates are not unjust and unreasonable and to limit the remaining opportunities for undue discrimination.

60. We also disagree with the commenters that claim that any concerns with current transmission planning and cost allocation processes are better dealt with on a case-specific basis rather than through a generic rule. While the concerns discussed above that are driving the need for these reforms may not affect each region of the country equally, we remain concerned that the existing transmission planning and cost allocation requirements of Order No. 890 are inadequate to ensure the development of more efficient and cost-effective transmission. It is well established that the choice between rulemaking and case-by-case adjudication ''lies primarily in the informed discretion of the administrative agency.'' [55] It is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry-wide problems facing us.

61. Nevertheless, the Commission recognizes that each transmission planning region has unique characteristics and, therefore, this Final Rule accords transmission planning regions significant flexibility to tailor regional transmission planning and cost allocation processes to accommodate these regional differences. The Commission recognizes that many transmission planning regions have or are in the process of taking steps to

[48] *Associated Gas Distributors,* 824 F.2d 981 at 1013.

[49] *Id.* at 1018–19.

[50] *Id.* at 1019.

[51] *Id.* at 1018–19.

[52] *TAPS* v. *FERC,* 225 F.3d 667 at 688; *National Fuel,* 468 F.3d 831.

[53] 824 F.2d 981 at 1008.

[54] *Niagara Mohawk Power Corp.* v. *FPC,* 379 F.2d 153, 159 (DC Cir. 1967).

[55] *SEC* v. *Chenery Corp.,* 332 U.S. 194, 203 (1947). *See also Alaska Power & Telephone Co.,* 98 FERC ¶ 61,092, at 61,277 (2002); *Trailblazer Pipeline Co.,* 79 FERC ¶ 61,274, at 62,183 (1997).

address some of the concerns described in this Final Rule. We encourage those regions to use the objectives and principles discussed in this Final Rule to guide continued development and compel them to abide by the requirements of this Final Rule.

62. The Commission recognizes the scope of these requirements, and to that end the Commission will continue to make its staff available to assist industry regarding compliance matters, as it did after Order No. 890. As stated above, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

D. Use of Terms

63. Before turning to the requirements of this Final Rule, the Commission defines several of the key terms used herein. For purposes of this Final Rule, there is a distinction between a transmission facility in a regional transmission plan and a transmission facility selected in a regional transmission plan for purposes of cost allocation. Transmission facilities selected in a regional transmission plan for purposes of cost allocation are transmission facilities that have been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because they are more efficient or cost-effective solutions to regional transmission needs. Those may include both regional transmission facilities, which are located solely within a single transmission planning region and are determined to be a more efficient or cost-effective solution to a regional transmission need, and interregional transmission facilities, which are located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost-effective solution to a regional transmission need. Such transmission facilities often will not comprise all of the transmission facilities in the regional transmission plan; rather, such transmission facilities may be a subset of the transmission facilities in the regional transmission plan. For example, such transmission facilities do not include a transmission facility in the regional transmission plan but that has not been selected in the manner described above, such as a local transmission facility or a merchant transmission facility. A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.

64. In distinguishing between transmission facilities selected in a regional transmission plan for purposes of cost allocation and other transmission facilities that also may be in the regional transmission plan, we seek to recognize that different regions of the country may have different practices with regard to populating their regional transmission plans. In some regions, transmission facilities not selected for purposes of regional or interregional of cost allocation nonetheless may be in a regional transmission plan for informational purposes, and the presence of such transmission projects in the regional transmission plan does not necessarily indicate an evaluation of whether such transmission facilities are more efficient or cost-effective solutions to a regional transmission need, as is the case for transmission facilities selected in a regional transmission plan for purposes of cost allocation. By focusing in parts of this Final Rule on transmission facilities selected in a regional transmission plan for purposes of cost allocation, we do not intend to disturb regional practices with regard to other transmission facilities that also may be in the regional transmission plan.

65. We also clarify that the requirements of this Final Rule are intended to apply to new transmission facilities, which are those transmission facilities that are subject to evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements of this Final Rule. The requirements of this Final Rule will apply to the evaluation or reevaluation of any transmission facility that occurs after the effective date of the public utility transmission provider's filing adopting the transmission planning and cost allocation reforms of the *pro forma* OATT required by this Final Rule. We appreciate that transmission facilities often are subject to continuing evaluation as development schedules and transmission needs change, and that the issuance of this Final Rule is likely to fall in the middle of ongoing planning cycles. Each region is to determine at what point a previously approved project is no longer subject to reevaluation and, as a result, whether it is subject to the requirements of this Final Rule.[56] Our intent here is that this Final Rule not delay current studies being undertaken pursuant to existing regional transmission planning processes or impede progress on implementing existing transmission plans. We direct public utility transmission providers to explain in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule.

66. Finally, nothing in this Final Rule should be read as the Commission granting approval to build a ''transmission facility in a regional transmission plan'' or a ''transmission facility selected in a regional transmission plan for purposes of cost allocation.'' For purposes of this Final Rule, the designation of a transmission project as a ''transmission facility in a regional transmission plan'' or a ''transmission facility selected in a regional transmission plan for purposes of cost allocation'' only establishes how the developer may allocate the costs of the facility in Commission-approved rates if such facility is built. Nothing in this Final Rule requires that a facility in a regional transmission plan or selected in a regional transmission plan for purposes of cost allocation be built, nor does it give any entity permission to build a facility. Also, nothing in this Final Rule relieves any developer from having to obtain all approvals required to build such facility.

III. Proposed Reforms: Transmission Planning

67. This section of the Final Rule has three parts: (A) Participation in the regional transmission planning process; (B) nonincumbent transmission developers; and (C) interregional transmission coordination.

A. Regional Transmission Planning Process

68. This part of the Final Rule adopts several reforms to improve regional transmission planning. First, building on the reforms that the Commission adopted in Order No. 890, this Final Rule requires each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and complies with existing Order No. 890 transmission planning principles. Second, this Final Rule adopts reforms under which

[56] We note that existing planning processes already include specific points at which a project will no longer be subject to reevaluation.

transmission needs driven by Public Policy Requirements are considered in local and regional transmission planning processes. By ''local'' transmission planning process, we mean the transmission planning process that a public utility transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890. These reforms work together to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers.[57] This, in turn, will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region. Each of these reforms is discussed more fully below.

69. Part A of section III has four subsections: (1) Need for reform concerning regional transmission planning; (2) legal authority for transmission planning reforms; [58] (3) regional transmission plan and Order No. 890 transmission planning principles; and (4) consideration of transmission needs driven by Public Policy Requirements.

1. Need for Reform Concerning Regional Transmission Planning

a. Commission Proposal

70. In the Proposed Rule, the Commission explained that, since the issuance of Order No. 890, it has become apparent to the Commission that Order No. 890's regional participation transmission planning principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. The Commission explained that, to meet that principle, each public utility transmission provider is currently required to coordinate with interconnected systems to: (1) Share system plans to ensure that the plans are simultaneously feasible and otherwise use consistent assumptions and data; and (2) identify system enhancements that could relieve congestion or integrate new resources.[59] The Commission thus did not require development of a transmission plan by each transmission planning region. Moreover, the Commission did not require regional transmission planning activities to comply with the transmission planning principles established in Order No. 890.[60] As such, the Commission proposed to require each public utility transmission provider to participate in a regional transmission planning process that satisfies the existing Order No. 890 transmission planning principles [61] and that produces a regional transmission plan.

71. The Commission also explained that, while it intended Order No. 890's economic planning studies transmission planning principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including transmission facilities to integrate new resources and loads on an aggregated or regional basis,[62] it recognized that its statements with respect to the Order No. 890 economic planning studies transmission planning principle may have contributed to confusion as to whether Public Policy Requirements may be considered in the transmission planning process.[63] The Proposed Rule stated that, when conducting transmission planning to serve native load customers, a prudent public utility transmission provider will not only plan to maintain reliability and consider whether transmission facilities or other investments can reduce the overall costs of serving native load, but also consider how to enable compliance with relevant Public Policy Requirements. The Proposed Rule further stated that, to avoid acting in an unduly discriminatory manner, a public utility transmission provider must consider these same needs on behalf of all of its customers. The Commission also noted that providing for incorporation of Public Policy Requirements in transmission planning processes, where applicable, could facilitate cost-effective achievement of those requirements.[64] The Commission therefore proposed to require each public utility transmission provider to amend its OATT so that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements.

b. Comments

72. A number of commenters support the Commission's preliminary determination in the Proposed Rule that there is a need to enhance the regional transmission planning process.[65] In supporting the proposal to implement new regional transmission planning requirements, Pennsylvania PUC argues that the current regional transmission planning process does not lend itself to the sort of open and transparent processes that allow state commissions to fully contribute to the regional transmission planning arena. Iberdrola Renewables states that the proposed reforms would advance the sound development of substantial new renewable energy resources, which it argues is critical to the nation's energy security, economic well-being, and the environment. AWEA states that existing transmission planning processes are too parochial in design and practice, and it suggests that the proposed transmission planning reforms will remedy these deficiencies.

73. However, other commenters argue that there is no need for reform of regional transmission planning requirements, at least on a nationwide basis.[66] Ad Hoc Coalition of Southeastern Utilities and Southern Companies argue that any problems that may exist regarding regional transmission planning are local in nature and the Commission should not undertake comprehensive, generic

[57] As in Order No. 890, the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. We leave such decisions in the first instance to the judgment of public utility transmission providers, in consultation with stakeholders participating in the regional transmission planning process.

[58] Because the legal authority concerns raised by commenters with regard to our regional transmission planning reforms and our interregional transmission coordination reforms are so closely related, we address these concerns together.

[59] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 45 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523).

[60] *See Entergy Services, Inc.,* 124 FERC ¶ 61,268, at P 104 (2008).

[61] These transmission planning principles are: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.

[62] Order No. 890's economic planning studies transmission planning principle requires that stakeholders be given the right to request a defined number of high priority studies annually through the transmission planning process, which are intended to identify solutions that could relieve transmission congestion or integrate new resources and loads, including facilities to integrate new resources or loads on an aggregated or regional basis. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 547–48.

[63] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 55–57 & n.76.

[64] *Id.* P 63.

[65] *E.g.,* 26 Public Interest Organizations; AWEA; Atlantic Grid; Clean Line; East Texas Cooperatives; Energy Future Coalition Group; Gaelectric; Iberdrola Renewables; Massachusetts Departments; NextEra; Pennsylvania PUC; Western Grid Group; and Wind Coalition.

[66] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Avista and Puget Sound; Bonneville Power; ColumbiaGrid; Indianapolis Power & Light; Southern Companies; and WestConnect.

reform. They argue that the regional transmission planning concerns expressed in the Proposed Rule are not present in the Southeast. ColumbiaGrid, Bonneville Power, Avista, and Puget Sound argue that regional transmission planning in the Northwest is robust. WestConnect makes a similar point regarding its collaborative planning process. Avista and Puget Sound state that the proposed reforms could threaten the continued viability of ColumbiaGrid's successful collaborative approach to planning because of concerns that some ColumbiaGrid members may not participate in that process if the Proposed Rule's reforms are adopted.

74. Others argue that the Commission should allow existing regional transmission planning processes to mature before taking action.[67] Sacramento Municipal Utility District contends that comprehensive transmission planning currently exists, planning studies are being performed, results are being evaluated, and interested stakeholders are actively engaged and, consequently, the Commission need not and should not take further action. Modesto Irrigation District states that existing regional and interconnectionwide transmission planning processes in the West provide an effective and comprehensive way to determine transmission needs and the transmission projects that efficiently address those needs in a manner that is consistent with the bottom up, stakeholder-driven transmission planning processes found in Order No. 890.[68] In reply, California Transmission Planning Group states that it agrees with commenters in the Western Interconnection that existing regional and interconnectionwide processes should continue to mature. It argues that comments expressing frustration with its planning process are indicative of the need to provide such processes time to mature, noting that its work has matured rapidly in the year since it was formed. Coalition for Fair Transmission Policy states that transmission investment has accelerated in recent years and, as a result, current transmission planning processes are working.

75. Others argue that the Proposed Rule would lead to undesirable outcomes. California Transmission Planning Group argues that the Proposed Rule would require it to transform itself from a regional coordinator of transmission studies and planning into a quasi-adjudicatory arbiter of the relative economic merits of specific transmission projects or alternatives and a gatekeeper to cost recovery and ratemaking mechanisms. California Transmission Planning Group also notes the legal constraints on many of its public agency members from assuming certain planning-related responsibilities. NorthWestern Corporation (Montana) does not believe the proposed approach is workable in the unorganized market areas in the West because the transmission provider, not the regional planning entity, has the obligation to the Commission through its tariff.

76. North Carolina Agencies argue that transmission planning must be initiated at the local and regional levels subject to state-level authority and based on the needs of customers who bear the burdens and benefits of the decisions resulting from the planning process. North Carolina Agencies also state that transmission developers who offer transmission projects as an alternative to locally planned solutions must be required to participate in and have their proposals considered as part of the relevant state planning process. Imperial Irrigation District points to potential confusion in the West, and states that it believes that the creation of a new regional transmission planning authority would impede, not hasten, transmission development.

77. However, Multiparty Commenters urge the Commission not to be swayed by arguments that reform of the transmission planning and cost allocation processes are not necessary simply because there has been an increase in transmission investment in the last few years, asserting that more investment does not mean that there is enough transmission being built to satisfy future needs, such as the interconnection of renewable resources. NextEra disagrees with commenters asserting that revising transmission planning procedures would disrupt existing processes under Order No. 890, arguing that those processes should be improved if there is a need to do so, as it would be wasteful to withhold needed reforms to observe how current processes would evolve. Powerex states that, although progress has been made in transmission planning processes since Order No. 890 was issued, more reforms are needed to ensure transparency and a level playing field for all stakeholders. National Grid agrees that the Commission should not wait to exercise its authority to require improvements to transmission planning processes. Twenty-six Public Interest Organizations argue that Southern Companies' claims that the transmission planning deficiencies identified in the Proposed Rule do not pertain to them and that implementation of the Proposed Rule would harm existing processes are unsupported by the facts and may reflect the inability of planning authorities to recognize the limits of their own procedures.

c. Commission Determination

78. We conclude that it is necessary to act under section 206 of the FPA to adopt the regional transmission planning reforms of this Final Rule, as discussed more fully below, to ensure just and reasonable rates and to prevent undue discrimination by public utility transmission providers. Our review of the record, including the comments submitted by numerous entities representing a variety of diverse viewpoints, makes clear to us that reform is necessary at this time. Specifically, we conclude that the existing requirements of Order No. 890 are inadequate to ensure that public utility transmission providers in each transmission planning region, in consultation with stakeholders, identify and evaluate transmission alternatives at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers. Moreover, the existing requirements of Order No. 890 do not necessarily result in the development of a regional transmission plan that reflects the identification by the transmission planning region of the set of transmission facilities that are more efficient or cost-effective solutions for the transmission planning region.

79. As the Commission explained in the Proposed Rule, when an individual public utility transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission alternatives that are proposed and then develops a local transmission plan that identifies what transmission facilities are needed to meet the needs of its native load (if any), transmission customers, and other stakeholders.[69] Through this process, the public utility transmission provider evaluates the

[67] *E.g.,* California Transmission Planning Group; Sacramento Municipal Utility District; and WestConnect.

[68] In describing these comments, we use the terms ''interconnectionwide'' and ''regional'' even though many commenters in the western United States used the term ''regional'' for interconnectionwide and ''subregional'' for regional. However, we will continue to use the terms ''interconnectionwide'' and ''regional'' in this Final Rule to make these comments clearer to readers outside of the West.

[69] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 51.

various alternatives available to determine a set of solutions that meet the system's needs more efficiently or cost-effectively than other proposed solutions. At the regional level, the Commission has relied on such processes when evaluating filings to help ensure that the recovery of costs associated with transmission facilities recovered through Commission-jurisdictional rates is just and reasonable.[70]

80. In some transmission planning regions, a similar level of analysis is undertaken by public utility transmission providers at the regional level, resulting in the development of a regional transmission plan that identifies those transmission facilities that are needed to meet the needs of stakeholders in the region. This occurs, for example, in each of the existing RTO and ISO regions, which, we note, serve over two-thirds of the nation's consumers.[71] In other transmission planning regions, however, as permitted by Order No. 890, public utility transmission providers use the regional transmission planning process as a forum to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans. We conclude that it is necessary to have an affirmative obligation in these transmission planning regions to evaluate alternatives that may meet the needs of the region more efficiently or cost-effectively. Given the potential impact such investments could have on rates for Commission-jurisdictional service, we conclude it is necessary to act at this time to enhance the transmission planning-related requirements imposed in Order No. 890.

81. In the absence of the reforms implemented below, we are concerned that public utility transmission providers may not adequately assess the potential benefits of alternative transmission solutions at the regional level that may meet the needs of a transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. For example, proactive cooperation among public utility transmission providers within a transmission planning region could better identify transmission solutions to more efficiently or cost-effectively meet the reliability needs of public utility transmission providers in the region. Further, regional transmission planning could better identify transmission solutions for reliably and cost-effectively integrating location-constrained renewable energy resources needed to fulfill Public Policy Requirements such as the renewable portfolio standards adopted by many states. Similarly, the development of transmission facilities that span the service territories of multiple public utility transmission providers may obviate the need for transmission facilities identified in multiple local transmission plans while simultaneously reducing congestion across the region. Under the existing requirements of Order No. 890, however, there is no affirmative obligation placed on public utility transmission providers to explore such alternatives in the absence of a stakeholder request to do so. We correct that deficiency in this Final Rule.

82. Based on our review of the record and comments in this proceeding, we also require each public utility transmission provider to amend its OATT to explicitly provide for consideration of transmission needs driven by Public Policy Requirements in both local and regional transmission planning processes. As the Commission noted in the Proposed Rule, existing transmission planning processes generally were not designed to account for, and do not explicitly consider, transmission needs driven by Public Policy Requirements. While transmission planning processes in some regions have evolved to reflect compliance with Public Policy Requirements, our review of the comments indicates that some transmission planning processes do not consider transmission needs driven by Public Policy Requirements.[72] As a result, some regions are struggling with how to adequately address transmission expansion necessary to, for example, comply with renewable portfolio standards. These difficulties are compounded by the fact that planning transmission facilities necessary to meet state resource requirements must be integrated with existing transmission planning processes that are based on metrics or tariff provisions focused on reliability or, in some cases, production cost savings.

83. As the Commission explained in the Proposed Rule, consideration of Public Policy Requirements raises issues similar to those raised in the Commission's discussion in Order No. 890 of the economic planning studies transmission planning principle.[73] When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to plan for transmission needs driven by Public Policy Requirements.[74] Therefore, we conclude that, to avoid acting in an unduly discriminatory manner against transmission customers that serve other loads, a public utility transmission provider must consider these same transmission needs for all of its transmission customers. Moreover, given that consideration of transmission needs driven by Public Policy Requirements could facilitate the more efficient and cost-effective achievement of those requirements, we conclude the reforms adopted herein are necessary to ensure that rates for Commission-jurisdictional services are just and reasonable.

84. Turning to the commenters opposed to these reforms, we are not persuaded by those who argue that any problems with existing transmission planning are local in nature and that the Commission should not undertake comprehensive, generic reform. As we explain above in the section on the general need for the reforms in this Final Rule, the Commission need not make specific factual findings to promulgate a generic rule to ensure

[70] *See, e.g., Transmission Technology Solutions, LLC, et al.* v. *Cal. Indep. Sys. Operator Corp.,* 135 FERC ¶ 61,077, at P 84 (2011) (rejecting complaint regarding California ISO transmission planning process and stating ''we find that CAISO reasonably concluded that PG&E's project is ultimately the most prudent and cost-effective solution. We find that for each of the incumbent and non-incumbent proposed projects, CAISO adequately considered lower cost alternatives, selected economically efficient solutions, accounted for more than just capital costs, and considered additional project benefits.'').

[71] *See IRC Brings Value to Reliability and Electricity Markets, available at http://www.isorto.org/site/c.jhKQIZPBImE/b.2603917/k.B00F/About.htm.* As discussed in section V below, to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission.

[72] For example, PJM acknowledges in its comments that under its existing transmission planning process, it cannot build transmission to anticipate the development of future generation, including renewable energy resources, that are not associated with specific generator interconnection requests.

[73] In Order No. 890, the Commission intended the economic planning studies principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including facilities to integrate new resources and loads on an aggregated or regional basis. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[74] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 63.

rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[75] As for those commenters that argue that the Commission should allow existing regional transmission planning processes to mature before acting, we believe that the discussion above illustrates that the requirements of the *pro forma* OATT are inadequate to ensure the development of more efficient or cost-effective solutions to regional needs. As we explained in section II above, while transmission planning processes have improved since the issuance of Order No. 890, we are concerned that the existing Order No. 890 requirements regarding transmission planning, as well as cost allocation, are insufficient to ensure that the evolution of transmission planning processes will occur in a manner that ensures that the rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential. At the same time, in response to North Carolina Agencies, we do not intend our reforms to preclude the ability of states to actively plan at the local level.

2. Legal Authority for Transmission Planning Reforms [76]

a. Commission Proposal

85. In the Proposed Rule, the Commission explained that the proposed reforms in the areas of regional transmission planning and interregional transmission coordination are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. The Commission also noted that the Proposed Rule builds on Order No. 890, in which the Commission required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process, among other things, in order to remedy opportunities for undue discrimination in the provision of transmission services.[77]

b. Comments

86. Several commenters argue that the Commission has adequate statutory authority to undertake the planning reforms in the Proposed Rule.[78] Iberdrola Renewables contends that the Commission has a firm legal basis to adopt the proposed reforms and has already relied on its authority to require regional transmission planning efforts in Order No. 890. In response to comments arguing that the Proposed Rule oversteps the Commission's authority, Exelon states that the proposed coordination reforms are well within the Commission's statutory authority to remedy the potential for undue discrimination in transmission planning activities, citing FPA sections 205 and 206, as well as *New York* v. *FERC*.[79] ITC Companies' reply comments also argue that the Commission has the legal authority to implement its proposals, citing the Commission's plenary authority over interstate transmission under FPA section 201 and noting that courts have broadly defined transmission in interstate commerce due to the interconnected nature of the transmission grid. Multiparty Commenters agree that the proposed reforms are within the Commission's plenary authority, and they believe that the Proposed Rule properly identifies deficiencies in transmission planning and cost allocation, and that requirements for transmission planning and cost allocation are necessary for fully competitive wholesale markets and thus fall squarely within the Commission's jurisdiction.

87. In response to those asserting that the Commission cannot require interregional agreements to coordinate planning because of section 202(a)'s voluntary coordination language, commenters assert that such arguments are contrary to precedent affirming Order Nos. 888 and 2000. Exelon notes that *Public Utility District No. 1 of Snohomish County* v. *FERC*,[80] which affirmed Order No. 2000, found that mandatory RTO rules did not run afoul of section 202(a). ITC Companies also assert that section 202(a) does not prohibit interregional planning agreements, contrary to some comments. Multiparty Commenters also argue that section 202 does not impose a limitation on the Commission's section 206 jurisdiction. In addition, commenters such as ITC Companies and Multiparty Commenters argue that the proposals do not preempt state jurisdiction over siting decisions. Twenty-six Public Interest Organizations argue that the FPA requires the Commission to address identified transmission planning deficiencies.

88. Some commenters argue that the Commission may consider public policy requirements. Exelon disagrees with those asserting that the Commission cannot require public utility transmission providers to consider the impacts of public policies under federal and state laws and regulations, and argues that the Commission is not establishing an independent obligation to satisfy such public policy requirements. Exelon states that courts have consistently recognized the Commission's need to adjust its regulation under the FPA to meet the changing needs of the industry.[81] LS Power explains that the proposal regarding public policy requirements is not an effort to pursue those goals but rather to ensure that transmission service is offered at just and reasonable rates. EarthJustice argues that, contrary to commenters challenging the Proposed Rule with respect to the consideration of public policy requirements, the Commission did not propose to infringe on state jurisdiction. EarthJustice argues that there is substantial evidence to support the Commission's conclusions in the Proposed Rule.[82]

89. Some commenters, however, assert that the Commission lacks jurisdiction to mandate the transmission planning reforms included in the Proposed Rule.[83] These commenters cite to section 202(a) of the FPA, which provides that coordination and interconnection arrangements are to be left to the voluntary action of public utilities. California ISO points to *Central Iowa Power Coop.* v. *FERC*,[84] which held that, in light of the voluntary nature of coordination under FPA section 202(a), the Commission's authority under FPA section 206 does not include the authority to require modifications to an otherwise just and reasonable tariff or jurisdictional agreement simply because the Commission has concluded that

[75] *See discussion supra* section II.C.

[76] As noted above, because the legal authority concerns raised by commenters with regard to both our regional transmission planning reforms and our interregional transmission coordination reforms are so closely related, we address these concerns together in this section of the Final Rule.

[77] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 1–2.

[78] *E.g.*, Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; and Multiparty Commenters.

[79] 535 U.S. 1 (2002).

[80] 272 F.3d 607 (DC Cir. 2001).

[81] Exelon (citing *New York* v. *FERC*, 535 U.S. 1 (2002)), *Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667 (DC Cir. 2000), and *Public Util. Dist. No. 1 of Snohomish Cty* v. *FERC*, 272 F.3d 607 (DC Cir. 2001).

[82] EarthJustice (citing *Louisiana Pub. Serv. Comm'n* v. *FERC*, 551 F.3d 1042, 1045 (DC Cir. 2008)).

[83] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; California ISO; ColumbiaGrid; Nebraska Public Power District; North Carolina Agencies; and Sacramento Municipal Utility District.

[84] 606 F.2d 1156 n. 36 (DC Cir. 1979) (*Central Iowa*).

alternative terms and conditions would better promote the interconnection and coordination of transmission facilities.

90. Several commenters state that the Commission's statutory authority is limited with respect to transmission siting decisions.[85] North Carolina Agencies assert that, with the exception of the Commission's limited backstop authority under FPA section 216, transmission planning and expansion fall strictly within the purview of state regulatory agencies and the Proposed Rule takes into account neither the Commission's lack of authority nor the long-standing authority of the states. Some commenters also explain that the states have authority with respect to integrated resource planning.[86]

91. Several others state that the Commission should confirm that transmission planning, even with the reforms adopted by this Final Rule, continues to be driven by the needs of load-serving entities.[87] Entities such as Ad Hoc Coalition of Southeastern Utilities, APPA, and Nebraska Public Power District point to FPA section 217(b)(4) as the only provision in the FPA that charges the Commission with transmission planning responsibilities, expressing concern that the proposed transmission planning reforms might be read to imply a greater focus on interests of stakeholders other than load-serving entities. National Rural Electric Coops argue that Order No. 890 struck an appropriate balance among interests and should be preserved.[88] APPA argues that the failure to address section 217 makes the Proposed Rule legally deficient. Additionally, several commenters contend the Commission's proposal is inconsistent with section 217, which they state recognizes the primacy of a franchised utility's obligation to do what is needed to fulfill its obligation to service, including the implementation of state-authorized plans for transmission construction.[89]

92. In response, ITC Companies contend that the Proposed Rule is compatible with section 217 regarding the needs of load-serving entities to fulfill their service obligations. They note that section 217 does not mandate the planning of transmission in interstate commerce based on state integrated resource plans or require that the Commission disregard the needs of renewable power producers or other generators.

93. Some commenters argue that the Commission lacks statutory authority to consider broad public policies.[90] Several commenters cite to *NAACP* v. *FPC*[91] for the proposition that the primary purpose of the Commission's statutory mission is to ensure reliable service at just and reasonable rates, and that Congress' direction to the Commission to act in furtherance of the public interest was not a broad license to promote the general welfare. Nebraska Public Power District and Ad Hoc Coalition of Southeastern Utilities add that the Commission has recognized this limitation in addressing its responsibility to consider environmental policy objectives under the National Environmental Policy Act.[92] PSEG Companies argue that the Commission's proposed reforms related to Public Policy Requirements are legally flawed. PSEG Companies state that the Commission's section 206 authority is not unbounded, citing to *California Independent System Operator Corp.* v. *FERC*,[93] where the court held that the Commission was not empowered to remove members of CAISO's board of directors under section 206. Further, PSEG Companies argue that there is no evidence to support the Commission's claims of undue discrimination under section 206.

94. Some commenters state that the Commission has not provided enough reasoning or adequate detail for the Proposed Rule so that parties can comment meaningfully on it, as required by section 553 of the Administrative Procedure Act (APA).[94] The commenters who argue this make three basic claims. They maintain that it is unclear from the Proposed Rule: (1) Whether the Commission proposes that regional and interregional plans will serve as the basis for (a) future orders requiring utilities to undertake construction consistent with the plans or (b) orders compelling utilities to defer to nonincumbent utilities in connection with the construction of transmission facilities needed for reliability purposes; (2) what public policies must be incorporated in transmission plans, or in what manner such policies should be reflected; and (3) what rate mechanism the Commission would employ to allocate costs incurred by nonincumbent transmission providers to entities with whom they have no service or contractual relationship.[95]

95. In addition, Electricity Consumers Resource Council and the Associated Industrial Groups argue that the Proposed Rule may represent a departure from the Commission's regulations under section 35.35(i)(ii), which establishes a rebuttable presumption that ''[a] project that has received construction approval from an appropriate state commission or state siting authority,'' applying the specified criteria, qualifies as being prudently incurred.[96] Southern Companies argue that, because the Proposed Rule did not identify what it would take to satisfy the public policy requirement, the proposal would violate the Due Process Clause's ''fair notice'' requirement.

96. Indianapolis Power & Light questions whether the Commission has satisfied FPA section 206 requirements, arguing that the Commission has not yet found that existing transmission planning (and cost allocation) provisions are unjust and unreasonable and that it has not ''fixed'' the rate or practice that it finds to be unjust and unreasonable.[97]

97. To ensure that any Final Rule will not directly or indirectly require a state or municipality to impair or violate private activity bond rules under section 141 of the Internal Revenue Code, City of Los Angeles Department of Water and Power urges the Commission to include in the Final Rule the following statement: ''All regional and interregional transmission plans and cost allocation methodologies must include a statement that municipal and public power participants are not required to take any action that would violate or impair a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, or any successor statute or regulation.'' Large

[85] *E.g.*, North Carolina Agencies; Florida PSC; Illinois Commerce Commission; and Nebraska Public Power District.

[86] *E.g.*, Alabama PSC; Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Florida PSC; and Commissioner Skop.

[87] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; National Rural Electric Coops; Transmission Access Policy Study Group; and APPA.

[88] Additionally, National Rural Electric Coops request that the Commission to confirm that transmission planning, even with any reforms the Commission adopts in this rulemaking, will continue to be driven in the first instance by the needs of load-serving entities. Transmission Access Policy Study Group makes a similar request.

[89] *E.g.*, Edison Electric Institute; Large Public Power Council; Nebraska Public Power; and Xcel.

[90] *E.g.*, Southern Companies; Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; and Large Public Power Council.

[91] *National Ass'n for the Advancement of Colored People* v. *FPC*, 425 U.S. 662 (1976).

[92] Nebraska Public Power District.

[93] 372 F.3d 395 (DC Cir. 2004) (*CAISO* v. *FERC*).

[94] *E.g.*, Nebraska Public Power District Comments (citing 5 U.S.C. 553, *Florida Power & Light Co.* v. *U.S.*, 846 F.2d 765, 771 (DC Cir. 1988), *Connecticut Light and Power Co.* v. *NRC*, 673 F.2d 525, 530 (DC Cir. 1982)); Large Public Power Council; Salt River Project Comments (citing *United Mine Workers or America* v. *MSHA*, 407 F.3d 1250, 1259 (DC Cir. 2005)).

[95] *E.g.*, Large Public Power Council and Nebraska Public Power District.

[96] 18 CFR 35.35(i)(ii).

[97] Indianapolis Power & Light (citing *Electrical Dist. No. 1* v. *FERC*, 774 F.2d 490, 492–93 (DC Cir. 1985)).

Public Power Council makes a similar comment. In its reply comments, APPA states that City of Los Angeles Department of Water and Power raises a practical and legal issue regarding the participation of public power systems in transmission planning and cost allocation activities, and APPA agrees that the statement suggested by City of Los Angeles Department of Water and Power would foster public power systems' participation in such processes.

98. Nebraska Public Power District states that as long as it participates in regional and interregional transmission planning through the SPP, it is able to commit to enter into regional planning through the SPP tariff, but cannot make such commitments outside of its present RTO membership. Nebraska Public Power District states that it is unclear what commitments may be called for in any transmission planning agreements, such as whether these agreements: (1) Will carry with them specified or unanticipated liability; and/or (2) may include an obligation to defer to regional or interregional transmission plans that could, in Nebraska Public Power District's judgment, interfere with what must be done to remain compliant with state law.

c. Commission Determination

99. We conclude that we have authority under section 206 of the FPA to adopt the reforms on transmission planning in this Final Rule. These reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Moreover, these reforms build on those of Order No. 890, in which the Commission reformed the *pro forma* OATT to, among other things, require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. As we explained in Order No. 890, we found that the existing *pro forma* OATT was insufficient to eliminate opportunities for undue discrimination, including such opportunities in the context of transmission planning.[98] We conclude that the reforms adopted in this Final Rule are necessary to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional transmission services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. We note that no party sought judicial review of the Commission's authority under Order No. 890 to adopt those reforms that we seek to enhance and improve upon here.

100. We disagree that section 202(a) of the FPA precludes us from adopting the transmission planning reforms contained in this Final Rule. Section 202(a) reads, in relevant part, as follows:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. * * * [99]

Section 202(a) requires that the interconnection and coordination, *i.e.,* the coordinated operation, of facilities be voluntary. That section does not mention planning, and nothing in it can be read as impliedly establishing limits on the Commission's jurisdiction with respect to transmission planning.

101. Transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The transmission planning process itself does not create any obligations to interconnect or operate in a certain way. Thus, when establishing transmission planning process requirements, the Commission is in no way mandating or otherwise impinging upon matters that section 202(a) leaves to the voluntary action of public utility transmission providers. As we discuss herein, section 202(a) refers to the coordinated operation of facilities.

102. Several commenters who argue that section 202(a) prohibits our proposal rely primarily on *Central Iowa* for support.[100] In *Central Iowa,* a party argued that the Commission should have used its authority under section 206 of the FPA to compel greater integration of the utilities in the Mid-Continent Area Power Pool (MAPP) than MAPP members had proposed. In seeking this goal, the party in question sought to have the Commission require MAPP participants ''to construct larger generation units and engage in single system planning with central dispatch.'' [101] The court held that given ''the expressly voluntary nature of coordination under section 202(a),'' the Commission was not authorized to grant that request.[102]

103. The court in *Central Iowa* was thus presented with a request that the Commission require an enhanced level of, or tighter, power pooling. Section 202(a) was relevant to the problem at issue in *Central Iowa* because the operation of the system through power pooling is its central subject matter. We, on the other hand, are focused in this proceeding on the transmission planning process, which is distinct from any specific system operations. Nothing in this Final Rule is tied to the characteristics of any specific form of system operations, and nothing in it requires any changes in the way existing operations are conducted. This Final Rule simply requires compliance with certain general principles within the transmission planning process regardless of the nature of the operations to which that process is attached. The court's interpretation of section 202(a) with respect to system operations is therefore irrelevant here.

104. Commenters point to dicta in *Central Iowa* based on section 202(a)'s legislative history that, they state, suggests that Congress intended that any coordination by public utilities with respect to transmission planning be voluntary. *Central Iowa* cites to, but does not quote directly, the legislative history to support the conclusion that ''Congress was convinced that 'enlightened self-interest' would lead utilities to engage voluntarily in power planning arrangements, and it was not willing to mandate that they do so.'' [103] The language from the legislative history is as follows:

> The committee is confident that enlightened self-interest will lead the utilities to cooperate with the commission and with each other in bringing about the economies which can alone be secured through the planned coordination which has long been advocated by the most able and progressive thinkers on this subject.[104]

105. In response, we note that section 202(a) does not mention the transmission planning process, and nothing in that section causes one to conclude that it was intended to address the transmission planning process that is the subject of this proceeding. There is thus no basis to resort to legislative

[98] *See, e.g.,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422.

[99] 16 U.S.C. 824(a).

[100] *E.g.,* ColumbiaGrid; Sacramento Municipal Utility District; and California ISO.

[101] *Central Iowa,* 606 F. 2d 1156 at 1166.

[102] *Id.* at 1168.

[103] *Id.*

[104] *See Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973) (citing S.Rep. No. 621, 74th Cong., 1st Sess. 49).

history for further clarification.[105] Moreover, even if resorting to legislative history was appropriate in this context, we note that this passage from the legislative history also does not refer to the transmission planning process that is the subject of this Final Rule. Instead, the legislative history refers to ''planned coordination,'' *i.e.,* to the pooling arrangements and other aspects of system operation that are the underlying focus of section 202(a). It is in this sense that *Central Iowa* must be understood when it refers to engaging ''voluntarily in power planning arrangements.'' The ''planned coordination'' mentioned in the legislative history cited in *Central Iowa* means ''planned coordination'' of the operation of facilities, not the planning process for the identification of transmission facilities. In short, neither *Central Iowa* nor the legislative history cited in that case involves or applies to the planning process for transmission facilities. Rather they deal with the coordinated, *i.e.,* shared or pooled, operation of facilities after those facilities are identified and developed. By contrast, this Final Rule deals with the planning process for transmission facilities, a separate and distinct set of activities that occur before the operational activities that are the underlying focus of section 202(a).

106. Similarly, section 202(a) has no bearing on whether the Commission can mandate requirements on regional and interregional cost allocation. The cost allocation requirements of this Final Rule do not mandate that any entity engage in any interconnection or coordination of facilities in contravention of the requirement in section 202(a) that these matters be left to the voluntary decisions of the entities in question. Section 202(a) does not address matters involved in cost allocation.

107. We acknowledge that there is longstanding state authority over certain matters that are relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction. However, nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule, like those of Order No. 890, are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs. In establishing these reforms, the Commission is simply requiring that certain processes be instituted. This in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities. For this reason, we see no reason why this Final Rule should create conflicts between state and federal requirements.

108. We disagree with the commenters who argue that this Final Rule is inconsistent with or precluded by, or legally deficient for failing to rely on, section 217 of the FPA.[106] Our approach in this Final Rule is to build on the requirements of Order No. 890 of ensuring open and transparent transmission planning processes to evaluate proposed transmission projects, a goal that does not conflict with FPA section 217. Indeed, we believe that this Final Rule is consistent with section 217 because it supports the development of needed transmission facilities, which ultimately benefits load-serving entities. The fact that this Final Rule serves the interests of other stakeholders as well does not place it in conflict with section 217. We thus cannot agree with Ad Hoc Coalition of Southeastern Utilities that we should ensure that our transmission planning and cost allocation reforms give systematic preference to any particular set of interests. Section 217 does not require this result. It only requires that we use our authority in a way that facilitates planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. We have indicated that we will follow a flexible approach that accommodates the needs and characteristics of particular regions, and we are confident that this approach can address the needs of load-serving entities in the Southeast and elsewhere.

109. We also disagree with commenters who argue that we lack jurisdiction to require the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process. In requiring the consideration of transmission needs driven by Public Policy Requirements, the Commission is not mandating fulfillment of those requirements. Instead, the Commission is acknowledging that the requirements in question are facts that may affect the need for transmission services and these needs must be considered for that reason. Such requirements may modify the need for and configuration of prospective transmission facility development and construction. The transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.

110. Our disagreement with commenters on this point can be best explained by considering the case that they use to support their arguments, *NAACP* v. *FPC.* In that case, the Court found that the Commission did not have power under the FPA or the Natural Gas Act (NGA) to construe its obligation to promote the public interest under those statutes as creating ''a broad license to promote general public welfare.''[107] Specifically, the Court found that the Commission's duty to promote the public interest under the FPA and NGA ''is not a directive to the Commission to seek to eradicate discrimination,'' and it thus did not authorize the Commission to promulgate rules prohibiting the companies it regulates from engaging in discriminatory employment practices merely because the statutes pertain to matters affected with a public interest.[108] The Commission is doing nothing analogous when specifying that transmission needs driven by Public Policy Requirements be taken into account in the transmission planning process.

111. Requiring the development of a regional transmission plan that considers transmission needs driven by Public Policy Requirements cannot be construed as pursuing broad general welfare goals that extend beyond matters subject to our authority under the FPA. Public Policy Requirements can directly affect the need for interstate transmission facilities, which are squarely within the Commission's jurisdiction. Moreover, we are not specifying the Public Policy Requirements that must be considered in individual local and regional transmission planning processes.[109] This further confirms that, in requiring that the transmission planning process

[105] *See, e.g., Connecticut Nat'l Bank* v. *Germain,* 503 U.S. 249, 253–54 (1992) (''[I]n interpreting a statute a court should always turn first to one, cardinal canon before all others. We have stated time and again that courts must presume that a legislature says in a statute what it means and means in a statute what it says there.'' (citations omitted)).

[106] Section 217(b)(4) of the FPA specifies that: ''The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.'' 16 U.S.C. 824q(b)(4).

[107] *NAACP* v. *FERC,* 425 U.S. 662 at 668.

[108] *Id.* at 670.

[109] *See infra* section III.A.4.

include the evaluation of potential solutions to identified transmission needs driven by Public Policy Requirements, the Commission is simply requiring the consideration of facts that are relevant to the transmission planning process. In doing so, it is neither pursuing nor enforcing any specific policy goals.

112. Other commenters cite *CAISO* v. *FERC* for the proposition that the Proposed Rule extends beyond our authority under the FPA. In that case, the court found that the Commission did not have authority under section 206 of the FPA to direct the California ISO to alter the structure of its corporate governance, concluding that the choosing and appointment of corporate directors is not a ''practice * * * affecting [a] rate'' within the meaning of the statute.[110] The court explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.'' [111] Unlike the corporate governance matters at issue in that proceeding, the transmission planning activities that are the subject of this Final Rule have a direct and discernable affect on rates. It is through the transmission planning process that public utility transmission providers determine which transmission facilities will more efficiently or cost-effectively meet the needs of the region, the development of which directly impacts the rates, terms and conditions of jurisdictional service. The rules governing the transmission planning process are therefore squarely within our jurisdiction, whether the particular transmission facilities in question are planned to meet reliability needs, address economic considerations, or meet transmission needs driven by a Public Policy Requirement.

113. We disagree with the commenters who argue that the Proposed Rule does not comply with the APA because the Proposed Rule does not provide enough reasoning or adequate detail to permit parties to comment meaningfully on it. Section 553(b)(3) of the APA requires that a notice of proposed rulemaking contain ''either the terms or substance of the proposed rule or a description of the subjects and issues involved.'' [112] The purpose of the requirement is to ensure that ''persons are 'sufficiently alerted to likely alternatives' so that they know whether their interests are 'at stake.' '' [113] Courts have held in this connection that a ''[n]otice of proposed rulemaking must be sufficient to fairly apprise interested parties of the issue involved * * *, but it need not specify every precise proposal which [the agency] may ultimately adopt as a rule.'' [114] We disagree with commenters arguing that this requires us to identify the issues that might be raised in future orders by the Commission should disputes arise as to the construction of transmission facilities in the regional transmission planning process. This Final Rule is focused on ensuring that there is a fair regional transmission planning *process,* not substantive outcomes of that process.

114. We disagree with Southern Companies' argument that the Proposed Rule violated the fair notice requirement of the Due Process Clause because it did not identify how the Public Policy Requirements in the transmission planning process would be satisfied. As explained above, fair notice requires that we apprise parties of the issues involved. In this respect, all interested parties have had fair notice and an opportunity to comment on the Commission's proposed requirement regarding the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process and to provide their perspectives, consistent with the notice and comment requirements of the APA. Moreover, the case that Southern Companies cite in support of their argument, *Trinity Broadcasting of Fla., Inc.* v. *FCC,*[115] is not on point. That case involved a denial by the Federal Communications Commission (FCC) of an application to renew a commercial television broadcast license that could have been renewed under a statutory preference in favor of minority-controlled firms. A majority of the applicant's board was made up of members of minority groups, but the FCC denied the application because the applicant had not satisfied its interpretation of minority control as *de facto* or ''actual'' control of operations. The court found that the agency had not given sufficient notice of its interpretation of minority control to justify punishment in the form of denial of the application. Nothing analogous is occurring here. *Trinity Broadcasting* did not involve a rulemaking proceeding, as is the case here, but rather an adjudication that raised the issue of ''[w]hat constitutes sufficiently fair notice of an agency's interpretation of a regulation to justify punishing someone for violating it?'' [116] A rulemaking such as the present proceeding does not involve the assessment of penalties for failure to comply with a particular regulation, and therefore the notice that is required before penalties can be assessed has no relevance here.

115. We also disagree that this Final Rule may represent a departure from section 35.35(i)(ii) of the Commission's regulations, which establishes a rebuttable presumption that a transmission project that has received construction approvals from relevant state regulatory agencies satisfies Order No. 679's [117] requirement that the transmission project is needed to ensure reliability or reduce the cost of delivered power by reducing congestion. The rebuttable presumption of prudent investment provided for in section 35.35(i)(ii) applies only to Commission determinations with respect to incentive-based rate treatments for investment in transmission infrastructure. The Proposed Rule does not ''represent a departure'' from this provision because the provision deals with matters that are not covered or affected by the Proposed Rule. Electricity Consumers Resource Council and Associated Industrial Groups therefore have not adequately explained why they believe the Proposed Rule represented such a departure.

116. With respect to Indianapolis Power & Light's assertion that the Commission has failed to satisfy FPA section 206, we conclude that we have met section 206's burden. Our review of the record demonstrates that existing transmission planning processes are unjust and unreasonable or unduly discriminatory or preferential. Specifically, we conclude that the record shows that, for the *pro forma* OATT (and, consequently, public utility transmission providers' OATTs) to be just and reasonable and not unduly discriminatory or preferential, it must be revised in the context of transmission planning to include the requirement that regional transmission planning processes result in the production of a regional transmission plan using a process that satisfies the specified Order No. 890 transmission planning

[110] *CAISO* v. *FERC,* 372 F.3d 395 at 403.

[111] *Id.*

[112] 5 U.S.C. 553(b)(3).

[113] *Spartan Radiocasting Co.,* v. *FCC,* 619 F.2d 314, 321 (4th Cir. 1980) (citing *South Terminal Corp.* v. *EPA,* 504 F.2d 646, 659 (1st Cir. 1974)).

[114] *Id.* 321–22 (citing *Consolidation Coal Co.* v. *Costle,* 604 F.2d 239, 248 (4th Cir. 1979)).

[115] 211 F.3d 618, 628 (DC Cir. 2000) (*Trinity Broadcasting*).

[116] *Trinity Broadcasting,* 211 F.3d 618 at 619.

[117] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g,* Order No. 679–A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g,* 119 FERC ¶ 61,062 (2007).

principles and that provides an opportunity to consider transmission needs driven by Public Policy Requirements. We conclude that these reforms satisfy the section 206 standard because they help ensure just and reasonable rates and remove those remaining opportunities for undue discrimination.

117. Finally, with respect to the concerns raised by City of Los Angeles Department of Water and Power, APPA, Nebraska Public Power District, and others regarding the legal issues associated with public power participation in the regional transmission planning processes, we make the following observations. First, as discussed in the section of this Final Rule addressing reciprocity, we reiterate that this Final Rule simply applies the reciprocity principles set forth in Order Nos. 888 and 890 regarding non-public utility transmission provider participation in transmission planning processes. Second, non-jurisdictional entities, unlike public utilities, may choose whether to join a regional transmission planning process and, to the extent they choose to do so, they may advocate for those processes to accommodate their unique limitations and requirements.

3. Regional Transmission Planning Principles

a. Commission Proposal

118. The Proposed Rule would require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that meets the following transmission planning principles: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies. This proposal did not include two of the Order No. 890 transmission planning principles, namely the cost allocation transmission planning principle and the regional participation transmission planning principle. More specifically, the Commission would require that each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that more efficiently or cost-effectively meet the needs of public utility transmission providers, their customers and other stakeholders.[118]

119. The Proposed Rule also would provide that a merchant transmission developer that does not seek to use the regional cost allocation process would not be required to participate in the regional transmission planning process, although such a developer would be required to comply with all reliability requirements applicable to transmission facilities in the transmission planning region in which its transmission project would be located.[119] To reiterate, merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates. The Proposed Rule states that such a merchant transmission developer would not be prohibited from participating—and, indeed, is encouraged to participate—in the regional transmission planning process.[120]

b. Comments

120. Many commenters agree that the Commission should require public utility transmission providers to produce a regional transmission plan using a process that complies with the Order No. 890 transmission planning principles.[121] NextEra supports the Commission's proposal provided that a regional transmission planning process produces a regional transmission plan with identified transmission facilities to be built in the near-term. Iberdrola Renewables contends that the current piecemeal, generation-driven approach to transmission development is inefficient and ineffective and hinders development of renewable energy resources. Duke states that it supports the requirement that a regional transmission plan be produced through a regional transmission planning process. Maine PUC believes that in New England, the distinction between different types of transmission projects (*i.e.,* reliability and market efficiency transmission facilities) has impeded the development of transmission facilities that would reduce congestion costs and provide greater access to low-cost supply, including renewable resources, and suggests that the Commission consider eliminating this distinction.

121. Most commenters addressing the proposed transmission planning reforms support the Commission's proposal to require public utility transmission providers to adopt several of the Order No. 890 transmission planning principles for the regional transmission planning process.[122] Some commenters ask the Commission to clarify that the existing Order No. 890 transmission planning principles would remain applicable to regional transmission planning processes.[123] Some commenters also seek clarification that individual transmission owners must comply with Order No. 890 transmission planning principles and have an OATT Attachment K on file with the Commission.[124] Transmission Dependent Utility Systems state that transmission owners must comply with Order No. 890 transmission planning principles even if they are planning local transmission projects in an RTO.

122. Several supporting the Proposed Rule stress that fair process, transparency, and robust stakeholder participation are important components of the transmission planning process.[125] PPL Companies state that all interested parties, especially those that may be allocated costs for a particular transmission project, should have an opportunity to provide meaningful input into the regional transmission planning process, and urge the Commission to require that historical and real-time data be made available to interested stakeholders. Transmission Dependent Utility Systems contend that transmission customers need to play an integral role in the regional transmission planning process. 26 Public Interest Organizations, Green Energy and 21st Century, and Western Independent Transmission Group state that transparency in transmission planning and access to models and data are critical to nonincumbent resources and grid infrastructure providers if these entities are to be effective participants in regional transmission plan development. Independent Energy Producers Association urges the Commission to emphasize that the

[118] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 51.

[119] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.23.

[120] *Id.* P 99.

[121] *E.g.,* Anabaric and PowerBridge; AWEA; City and County of San Francisco; DC Energy; Duke; Duquesne Light Company; East Texas Cooperatives; Energy Future Coalition Group; LS Power; MISO; National Grid; NEPOOL; New England States' Committee on Electricity; New England Transmission Owners; NextEra; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Wilderness Society and Western Resource Advocates; and Wisconsin Electric Power Company.

[122] *E.g.,* ISO New England and SPP.

[123] *E.g.,* East Texas Cooperatives and Champlain Hudson.

[124] *E.g.,* Transmission Dependent Utility Systems and Old Dominion.

[125] *E.g.,* PPL Companies; DC Energy; Direct Energy; 26 Public Interest Organizations; Green Energy and 21st Century; Western Independent Transmission Group; City of Santa Clara; Natural Resources Defense Council; New Jersey Division of Rate Counsel; and Iberdola Renewables.

openness, transparency, and inclusiveness criteria of Order No. 890 should apply to all phases of the transmission planning process. New Jersey Board suggests that transmission providers be required to state the baseline methodology on which load forecasts are based. However, Anbaric and PowerBridge suggest consideration of internal procedures to treat transmission project information as confidential, including protections to ensure that transmission projects that are not selected in the regional transmission plan will remain confidential.

123. Some commenters also address dispute resolution issues in the regional transmission planning process. City of Santa Clara believes that transmission planning processes should include an effective and meaningful dispute resolution process, including the ability to request Commission resolution of unresolved disputes. Transmission Access Policy Study Group argues that guidance from the Commission is needed to ensure that the dispute resolution process is useful, suggesting that use of reasonable, nondiscriminatory criteria to minimize the potential for discriminatory results, particularly with regard to the inclusion or exclusion of project proposals in a regional transmission plan and the consideration of public policy objectives in the transmission planning process. Transmission Access Policy Study Group suggests that the Commission establish a backstop dispute resolution or expedited complaint process to have a forum for addressing disputes regarding transmission projects selected or not selected in regional transmission plans.

124. Some commenters recommend that the Commission continue to recognize regional flexibility with respect to transmission planning processes.[126] Kansas City Power & Light and KCP&L Greater Missouri supports the Proposed Rule's suggestion that the Commission would defer to each region to develop transmission planning processes that address regional needs, noting that each region has developed differently and that not all regions are at the same level of maturity. Northern Tier Transmission Group states that the Commission should provide flexibility as to the manner in which regional plans are produced, emphasize expected results rather than process, and clarify that the region may continue to rely on a ''bottom-up'' process in developing the plan. SPP recommends that transmission planning authorities be permitted to develop, through their stakeholder processes and in consultation with state regulatory commissions, strategies and metrics to achieve region-appropriate compliance with the Final Rule.

125. Many entities that support the Proposed Rule believe that the regional transmission planning process in which they participate already satisfies the proposed requirements.[127] ISO/RTO Council asks that the Final Rule reflect that ISOs and RTOs already satisfy the requirements and that no further demonstration or tariff language be required in a future compliance filing with the exception of any new or altered requirements imposed by the Final Rule. In response, 26 Public Interest Organizations agree that the proposed reforms should not modify or interfere with progress being made by transmission planners with transmission planning processes that comply with or exceed Order No. 890 requirements and that only those tariff provisions that are affected by the Final Rule need to be filed.

126. On the other hand, Iberdrola Renewables states that the Commission should make clear that reliance on existing institutions and approaches would be adequate only if they can effectively implement the Commission's goals of driving needed transmission infrastructure investment. To that end, it states that in areas not covered by RTOs or ISOs, new regional agreements would be needed to ensure that the transmission providers in the region have a governance structure for undertaking the regional and interregional transmission planning obligations and a workable mechanism for sharing costs consistent with the cost allocation guidelines, and clarify the factors it would consider in determining whether a particular regional proposal or compliance filing has sufficiently broad regional support to merit any deference.

127. Some commenters ask the Commission to clarify the term ''transmission planning region'' as it relates to the requirements of the Proposed Rule.[128] Indianapolis Power & Light and Powerex ask the Commission to define ''region'' in a Final Rule and include a definition of transmission planning region in whatever regulations are promulgated. California Municipal Utilities state that they believe regional consolidation of transmission planning regions should not be forced and that more detail is needed from the Commission for its members to determine if current transmission planning processes meet the requirements of the Proposed Rule. Solar Energy Industries and Large-scale Solar contend that the Commission should ensure that, on the review of compliance filings, the scope of the self-selected planning regions does not create inadvertent planning seams that inhibit the development of transmission projects needed to meet public policy requirements established by state or federal laws or regulations.

128. Several commenters urge the Commission to clarify that existing ISOs and RTOs are considered regions for purposes of transmission planning.[129] However, ITC Companies state that RTO boundaries are not always the right ones for transmission planning, and ITC Companies are concerned that, given the focus of RTOs on developing and running energy markets, it might be difficult for RTOs to plan transmission from a truly independent perspective. Instead, ITC Companies suggest that the planning function be split off from the market function so that there is a truly independent planning authority. In reply, California ISO argues that ITC Companies' recommendation is tantamount to mandating the creation of new entities, which it argues the Commission cannot do. AWEA asks the Commission to clarify that more than one organized market could form a single region for transmission planning and cost allocation purposes.

129. Commenters express different views on defining transmission planning regions outside of the ISO and RTO context. MISO Transmission Owners suggest that, where ISOs or RTOs do not exist, the Commission should allow each transmission provider to propose its own definition of what it considers its transmission planning region. Further, they state that the Commission should not define the term ''transmission planning region'' to be any larger or broader than an RTO or ISO region. MISO states that public utility transmission providers not associated with existing RTOs should either be required to form transmission regional planning areas with each other

[126] *E.g.,* Kansas City Power & Light and KCP&L Greater Missouri; Edison Electric Institute; and WIRES.

[127] *E.g.,* Bonneville Power; Duke; Massachusetts Departments; California ISO; Sunflower and Mid-Kansas; MISO Transmission Owners; California Commissions; MISO; New England States' Committee on Electricity; Indianapolis Power & Light; Northeast Utilities; ISO New England; New York ISO; Southern Companies; and Long Island Power Authority.

[128] *E.g.,* NextEra; Clean Line; California Municipal Utilities; American Transmission; and Arizona Corporation Commission.

[129] *E.g.,* ISO/RTO Council; California ISO; MISO Transmission Owners; Indianapolis Power & Light; and NextEra.

or participate in regional transmission planning with an adjacent RTO. Some commenters ask the Commission to determine that, in non-RTO regions, a single transmission provider or utility family cannot serve as a transmission planning region.[130] Transmission Access Policy Study Group urges the Commission to specify that transmission planning regions in areas outside of RTOs include at least two transmission providers and be at least as large as the smaller of a state or one of NERC's Regional Entities. NextEra suggests that, in non-RTO areas, geographic scope should be determined by factors such as the level of interconnections between utilities, power flows, boundaries of existing NERC regions, and historical coordination practices.

130. Ad Hoc Coalition of Southeastern Utilities claim that the Proposed Rule makes several incorrect statements concerning what constitutes a region for transmission planning purposes in the Southeast.[131] They note that the Proposed Rule references both regional and interregional organizations and processes (including NERC regional entities) as being regional for purposes of the Proposed Rule and assert that a holding that only RTO regions are sufficiently encompassing to meet the proposed requirements would be arbitrary and capricious. Given that the Commission has previously recognized that the South Carolina Regional Transmission Planning (SCRTP) process complies with Order No. 890, and as such is a ''regional transmission planning process,'' South Carolina Electric & Gas asks the Commission to clarify that the SCRTP constitutes a ''regional transmission planning process'' as contemplated by the Proposed Rule. Colorado Independent Energy Association supports the designation of WestConnect as a regional transmission planning organization for the purposes of transmission planning and development in Colorado and to make findings to that effect in this Final Rule. Florida PSC and Commissioner Skop argue that if the Commission adopts a definition of ''region'' that does not recognize Florida as a distinct transmission planning region, and Florida becomes part of a multistate region, then it is unclear what role the Florida PSC would retain, if any, over the transmission planning and cost allocation processes in Florida.[132]

131. Many commenters recommend that transmission providers should evaluate both transmission and non-transmission solutions during the regional transmission planning process.[133] 26 Public Interest Organizations and Dayton Power and Light assert that consideration of non-transmission solutions with all other resource options is needed to determine the most cost-effective way to meet grid needs. 26 Public Interest Organizations ask the Commission to establish minimum requirements for: what types of resources should be assessed; how assessments should be conducted; and what types of modeling and sensitivity analyses are needed to estimate and compare the costs and benefits of option, implementation timelines, and relative risks of various resource choices. New Jersey Board believes that transmission providers should provide peak load reduction data that demonstrate the effect of demand response and energy efficiency on baseline forecasts. MISO supports the consideration of non-traditional solutions so long as this process does not interfere with state authority over integrated resource planning. Western Grid Group and Pattern Transmission suggest that resource planning and transmission planning should be reintegrated.

132. On the other hand, Ad Hoc Coalition of Southeastern Utilities states that a requirement for regional transmission planning processes to consider both transmission and non-transmission solutions is inconsistent with transmission planning procedures in the Southeast. It explains that non-transmission solutions are typically considered in integrated resource planning and request for proposal processes during the current ''bottom-up'' transmission planning process. It states that including a generation resource as an alternative during the regional transmission planning process would convey a right of generation planning to the Commission that would be inconsistent with state law. Accordingly, it states that there are no transmission planning gaps in the Southeast that the Commission needs to address. In its reply comments, Ad Hoc Coalition of Southeastern Utilities argues that such a policy would be inappropriate because there would be winners and losers in any given state, such a ''top-down'' process would risk losing the emphasis on consumers that currently exists in the state-regulated processes. Ad Hoc Coalition of Southeastern Utilities, in responding to comments by Western Grid Group and Pattern Transmission, argues that transmission planning and resource planning in the Southeast have not diverged and that further reforms are unnecessary. Southern Companies agree.

133. MISO Transmission Owners ask the Commission to provide additional guidance regarding the meaning of ''non-transmission solutions'' and which of these solutions transmission providers are required to include in their transmission planning processes. MISO Transmission Owners state that if non-traditional solutions must be considered, then the Commission should clarify that they are required to participate in the transmission planning process on a similar basis as transmission projects.

134. Other commenters ask for clarification and guidance from the Commission on other transmission planning-related issues associated with the Proposed Rule. WIRES believes that the Commission should consider additional rules that promote consistent transmission planning cycles, stakeholder procedures, action timelines, and criteria for evaluating project proposals. Transmission Access Policy Study Group also suggests that the Commission require regular updating of regional transmission plans, and require jurisdictional transmission providers to file, for public comment, a ''planning report card'' identifying the projects proposed during the transmission planning process, the projects approved and included in the regional transmission plan, and the projects that were proposed but excluded from the plan and the reasons those proposed projects were rejected. Transmission Access Policy Study Group states that the Final Rule should subject decisions as to which facilities are included in a regional transmission plan to justification and objective evaluation to prevent discrimination and unjust and unreasonable rates.

135. AEP asserts that a significant flaw in typical transmission planning processes is the failure to consider benefits beyond the near-term.

[130] *E.g.,* AWEA; Clean Line; G&T Cooperatives; Integrys; and NextEra.

[131] In reply comments, South Carolina Office of Regulatory Staff state that it concurs with Ad Hoc Coalition of Southeastern Utilities' views regarding the uniqueness of transmission planning in the Southeast.

[132] Additionally, Florida PSC and Commissioner Skop express concern about the lack of Florida-based commenters, noting that either Florida utilities joined a broader coalition of commenters or, as in the case of NextEra, did not comment from the perspective of its Florida-based utility. Florida PSC and Commissioner Skop ask the Commission to take the lack of Florida-specific points of view into account when it considers its proposals.

[133] *E.g.,* AWEA; California Commissions; Wisconsin Electric; Omaha Public Power District; Dayton Power and Light; Eastern Environmental Law Center; Environmental NGOs; NRG; Vermont Electric; EarthJustice; and SPP.

Therefore, AEP recommends that the Commission direct each transmission planning region to develop a long-term plan that utilizes a 20–30 year planning horizon in the determination of need analysis (while still permitting RTOs to annually evaluate shorter-term projects needed to complement the long-term plan). AEP argues that the useful life of any transmission facility is likely to exceed 40 years and, consequently, the most efficient transmission planning process should cover a minimum span of 20 years, and cites to SPP's and California ISO's transmission planning processes, which use 20-year planning horizons.

136. Primary Power supports the concept that every transmission provider must participate in a regional transmission planning process where specific projects are determined to be in the public convenience and necessity, and urges the Commission to devise threshold requirements ensuring that transmission planners have a degree of independence from market participants that would promote equitable and economically supportable results in terms of which transmission facilities are built and who ultimately pays for them. Some commenters also ask the Commission to clarify that least-cost planning is a driver of the transmission planning process. Transmission Dependent Utility Systems state that both the regional and interregional transmission planning processes adopted by the Final Rule should include clarification that coordination of reliability and economic transmission planning includes identifying optimal solutions to congestion for all transmission customers and load-serving entities across the region. Transmission Dependent Utility Systems recommend that the Commission clarify this concept in the Final Rule and explicitly recognize a joint optimization requirement.

137. Solar Energy Industries and Large-scale Solar suggest that the Commission require holistic long-term planning on a regional basis, in which the interaction of proposed projects with other projects across the region, as well as the integration of renewable resources, distributed generation, and demand response is considered. Transmission Agency of Northern California asks the Commission to clarify that a regional transmission planning ''process'' need not be narrowly defined as participation in a single set of procedures and that the transmission planning process need not serve every planning purpose. Arizona Corporation Commission seeks clarification on who would determine whether a transmission project is a reliability project within the context of the regional transmission planning process. Arizona Corporation Commission suggests that state-level entities, such as state utility commissions, should continue to determine whether a transmission project is a reliability project during line siting and/or determination of need proceedings. Additionally, it states that all proposed transmission projects should be freshly evaluated in each transmission planning cycle so that projects are aligned with transmission needs at the time and adequately incorporate current public policy requirements.

138. Some commenters seek assurance from the Commission that the needs of states and load-serving entities would be considered in the regional transmission planning process. NARUC states that the Final Rule should identify the states as key players in any transmission planning process, pointing to the primary role of states in transmission siting. E.ON emphasizes that the Commission should work to ensure that the Final Rule's planning requirements not give rise to new impediments to a local transmission owning utility's ability to efficiently satisfy customer needs under state service obligations. E.ON suggests that the Commission incorporate the following requirements in its Final Rule: regional and interregional transmission planning processes should be sufficiently flexible to accommodate the real-time requirements of a transmission owner and operator's native load customers; and the transmission planning process should recognize that the obligation to serve still exists in a number of jurisdictions and that any regional plan or process needs to allow for the fact that it is that obligation that drives transmission planning.

139. Others are concerned about the applicability of the Proposed Rule to currently pending transmission projects. Atlantic Wind Connection seeks clarification that sponsored projects with a pending request for inclusion in a regional transmission plan should be studied under the requirements of the Final Rule without undue delay, including delays resulting from any proposed procedural requirements. Edison Electric Institute argues that the Final Rule should apply to projects only on a going-forward basis, and a project identified in an existing plan should not be subject to bumping in a revised transmission planning process filed in compliance with a Final Rule. Northeast Utilities states that the Final Rule should avoid harming projects already included in the transmission planning process.

140. Some commenters ask the Commission to establish a funding mechanism to allow interested parties that are not market participants to fully participate in the regional transmission planning process. twenty-six Public Interest Organizations assert that an essential element of robust and broadly supported regional planning is the participation of non-market participants and that this requires ongoing provider assistance. They state that, because non-market stakeholders have neither the financial resources nor staff expertise to participate effectively in regional transmission plan development processes without special assistance, the Commission should direct transmission providers to facilitate participation of these stakeholders through a funding mechanism to cover reasonable technical assistance and other participation costs. They conclude that these costs can be rolled into the rates of the transmission service providers. Western Grid Group offers suggestions as to how a funding mechanism could be implemented. Additionally, EarthJustice and Environmental Groups urge the Commission to encourage meaningful public participation in the regional transmission planning process, arguing that non-market participation is vital to achieving just, reasonable, and non-discriminatory system plans, and explaining that substantial financial assistance is necessary to assure such meaningful participation.

141. Some commenters, such as AWEA and Transmission Access Policy Study Group, support a requirement that there be an obligation to construct projects identified in regional transmission plans. AWEA recognizes that, while regional and interregional cost allocation arrangements may alleviate some of the impediments to building transmission facilities, an obligation to build projects identified in the regional transmission plan in non-RTO regions would help ensure that transmission facilities ultimately are constructed. In its reply comments, First Wind supports AWEA's comments. Transmission Access Policy Study Group suggests that the Commission can stimulate the construction of new projects, without expanding transmission providers' obligation to build. It suggests requiring development of a process to obtain construction commitments, with accountability for those commitments. Transmission Access Policy Study Group states that the Final Rule should include a timely post-plan process for: (1) securing commitments by transmission providers

(or others) to build the transmission facilities identified in the regional plan; and (2) holding transmission providers and others that commit to construct transmission facilities included in the regional base model accountable for doing so.

142. On the other hand, Edison Electric Institute argues that the identification of transmission facilities in a transmission plan does not impose an obligation to build them. In addition, Salt River Project asserts that a transmission plan is not a specific blueprint of projects that must be built and states that regional planning provides the valuable service of comparing and contrasting individual potential projects with the decision to build any given project coming after the transmission planning process, with only those projects deemed superior getting built. Salt River Project states that not all projects identified by the plan should be or will be developed. Large Public Power Council points to statements in the Proposed Rule providing that the Commission's intention is not to require construction, and that this decision not to compel construction is grounded in limitations on the Commission's statutory authority.

143. A number of commenters address the issue of whether merchant transmission developers, *i.e.,* those transmission developers that are not seeking regional cost recovery for proposed transmission projects, should be required to participate in the regional transmission planning process. Some commenters state that the Commission should clarify in the Final Rule that merchant transmission developers should not be required to participate in the regional transmission planning process.[134] Clean Line states that, if ratepayers are not bearing development risk and the developer is not seeking regional cost allocation for its project, then it should not be required to participate in the regional transmission planning process. Allegheny Energy Companies note that, in PJM's regional transmission planning process, such merchant transmission developers are not required to participate if they do not wish to do so. New York ISO states that it supports the proposal to not require transmission developers that do not seek to take advantage of a regional transmission cost allocation mechanism to participate in the regional transmission planning process. LS Power states that it understands that merchant transmission developers that did not participate in the regional transmission planning process would still be required to provide to public utility transmission providers the information that is needed, for example, for the reliable operation of the transmission grid.

144. However, others support requiring merchant transmission developers to participate in the regional transmission planning process.[135] APPA states that the reasons for engaging in coordinated planning extend well beyond eligibility for inclusion in the regional transmission cost allocation mechanisms, noting that the development of transmission projects is a time-consuming and expensive endeavor. APPA argues that it is important for transmission planners to know about and fully analyze all of the various transmission alternatives to ascertain the impact of existing and proposed projects on other regional transmission facilities. Transmission Access Policy Study Group is concerned that exempting merchant transmission developers from the regional transmission planning process could cause the mandatory process to plan around *ad hoc* merchant transmission projects and would undermine the benefits of regional transmission planning, such as the development of a right-sized grid, and creates the potential for free ridership. In reply to Clean Line, Edison Electric Institute states that viable merchant transmission projects must be included in the regional transmission planning process, because such projects may have significant reliability, operational, and economic impacts on the transmission system.

145. Finally, some commenters recommend that the Commission strongly encourage nonincumbent participation even in cases where they are not seeking regional cost recovery. California Commissions state that nonincumbent transmission developers that seek cost recovery via rolled-in rates should participate fully in the regional transmission planning process but believes that participation by merchant transmission developers that do not seek such cost recovery should be strongly encouraged to the extent feasible with regard to planning, but not to cost recovery. In its reply comments, Powerex notes that many commenters were opposed to exempting merchant transmission developers and thus recommended that the Commission encourage their participation in the regional transmission planning process.

c. Commission Determination

146. This Final Rule requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890 identified below. We determine that such transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders. This will, in turn, help ensure that the rates, terms and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.

147. Order No. 890 required public utility transmission providers to coordinate at the regional level for the purpose of sharing system plans and identifying system enhancements that could relieve congestion or integrate new resources.[136] The Commission did not specify, however, whether such coordination with regard to identifying system enhancements included an obligation for public utility transmission providers to take affirmative steps to identify potential solutions at the regional level that could better meet the needs of the region. As a result, the existing requirements of Order No. 890 permit regional transmission planning processes to be used as a forum merely to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans. Consistent with the economic planning requirements of Order No. 890, regional transmission planning processes also must respond to requests by stakeholders to perform studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources or loads on an aggregated or regional basis.[137] Again, no affirmative obligation was placed on public utility transmission providers within a region to undertake such analyses in the absence of requests by stakeholders. There is also no obligation for public utility transmission providers within

[134] *E.g.,* Allegheny Energy Companies; Champlain Hudson; Clean Line; H–P Energy Resources; LS Power; and New York ISO.

[135] *E.g.,* APPA; Large Public Power Council; Massachusetts Municipal and New Hampshire Electric; MISO Transmission Owners; National Rural Electric Coops; Nebraska Public Power District; New England States Committee on Electricity; Northern Tier Transmission Group; Ohio Consumers Counsel and West Virginia Consumer Advocate Division; Old Dominion Electric Cooperative; Six Cities; Transmission Agency of Northern California; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

[136] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[137] *Id.*

the region to develop a single transmission plan for the region that reflects their determination of the set of transmission facilities that more efficiently or cost-effectively meet the region's needs.

148. We address these deficiencies in the requirements of Order No. 890 through this Final Rule, beginning with the requirement that public utility transmission providers participate in a regional transmission planning process that produces a regional transmission plan. Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. This could include transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements, as discussed further below. When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed non-transmission alternatives on a comparable basis. If the public utility transmission providers in the transmission planning region, in consultation with stakeholders, determine that an alternative transmission solution is more efficient or cost-effective than transmission facilities in one or more local transmission plans, then the transmission facilities associated with that more efficient or cost-effective transmission solution can be selected in the regional transmission plan for purposes of cost allocation.[138]

149. We acknowledge that public utility transmission providers in some regions already meet or exceed this requirement.[139] As with other requirements in this Final Rule, our intent here is to establish a minimum set of obligations for public utility transmission providers that, as some commenters note, are not currently undertaking sufficient transmission planning activities at the regional level. We decline, however, to specify in this Final Rule a particular set of analyses that must be performed by public utility transmission providers within the regional transmission planning process. There are many ways potential upgrades to the transmission system can be studied in a regional transmission planning process, ranging from the use of scenario analyses to production cost or power flow simulations. We provide public utility transmission providers in each transmission planning region the flexibility to develop, in consultation with stakeholders, procedures by which the public utility transmission providers in the region identify and evaluate the set of potential solutions that may meet the region's needs more efficiently or cost-effectively. We will review such mechanisms on compliance, using as our yardstick the statutory requirements of the FPA, Order No. 890 transmission planning principles, and our precedent regarding compliance with the Order No. 890 transmission planning principles, and issue further guidance as necessary.[140]

150. Because of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, stakeholders must be provided with an opportunity to participate in that process in a timely and meaningful manner. Therefore, we apply the Order No. 890 transmission planning principles to the regional transmission planning process, as reformed by this Final Rule. This will ensure that stakeholders have an opportunity to express their needs, have access to information and an opportunity to provide information, and thus participate in the identification and evaluation of regional solutions. Ensuring access to the models and data used in the regional transmission planning process will allow stakeholders to determine if their needs are being addressed in a more efficient or cost-effective manner. Greater access to information and transparency also will help stakeholders to recognize and understand the benefits that they will receive from a transmission facility in a regional transmission plan. This consideration is particularly important in light of our reforms that require that each public utility transmission provider have a cost allocation method or methods for transmission facilities selected in a regional transmission plan that reflects the benefits that those transmission facilities provide.

151. Specifically, the requirements of this Final Rule build on the following transmission planning principles that we required in Order No. 890: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.[141] In Order No. 890, we required that each public utility transmission provider adopt these transmission planning principles as part of its individual transmission planning process. In this Final Rule, we expand the Order No. 890 requirements by directing public utility transmission providers to adopt these requirements with respect to the process used to produce a regional transmission plan. We conclude that it is appropriate to do so to ensure that regional transmission planning processes are coordinated, open, and transparent.[142] Accordingly, we require public utility transmission providers to develop, in consultation with stakeholders,[143] enhancements to their regional transmission planning processes, consistent with these transmission planning principles.

152. We conclude that, without the requirement to meet the Order No. 890 transmission planning principles, a regional transmission planning process will not have the information needed to

[138] As discussed in section IV.F.6, below, we conclude that the issue of cost recovery associated with non-transmission alternatives is beyond the scope of this Final Rule, which addresses the allocation of the costs of transmission facilities.

[139] As noted above, to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission. Moreover, to the extent necessary, we clarify that nothing in this Final Rule is intended to modify or abrogate governance procedures of RTOs and ISOs.

[140] In developing their compliance filings, public utility transmission providers and interested parties should review the requirements as set forth in Order No. 890, Order No. 890–A, and our orders on compliance filings submitted by public utility transmission providers for guidance on what each of these transmission planning principles requires. For example, as a starting point, a public utility transmission provider should review the orders addressing its own compliance filings and the compliance filings for public utility transmission providers in its region. We do not address these principles in detail here, except with respect to the consideration of non-transmission alternatives in the regional transmission planning process and other discrete issues raised by commenters.

[141] We do not include the regional participation transmission planning principle and the cost allocation transmission planning principle here because we address interregional transmission coordination and cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation elsewhere in this Final Rule.

[142] Although the explicit requirement for a public utility transmission provider to participate in a regional transmission planning process that complies with the Order No. 890 transmission planning principles identified above is new, we note that the existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these Final Rule requirements.

[143] The term "stakeholder" is intended to include any party interested in the regional transmission planning process. This is consistent with the approach taken in Order No. 890. *See, e.g., Southern Co. Svcs., Inc.,* 127 FERC ¶ 61,282, at P 14–16 (2009).

assess the impact of proposed transmission projects on the regional transmission grid. Additionally, absent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.

153. A number of commenters specifically address the treatment of non-transmission alternatives in the regional transmission planning process. Order No. 890's comparability transmission planning principle requires that the interests of public utility transmission providers and similarly situated customers be treated comparably in regional transmission planning.[144] In response to Order No. 890, public utility transmission providers have identified in their transmission planning processes where, when, and how transmission and non-transmission alternatives proposed by interested parties will be considered. As noted in Order No. 890, the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed.[145] As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with public utility transmission providers. With that said, the Commission intends that the regional transmission planning processes provide for the timely and meaningful input and participation of stakeholders in the development of regional transmission plans.[146]

154. We disagree with those commenters that assert that non-transmission alternatives only should be considered in the local transmission planning process. We recognize that generation, demand response, and energy efficiency options often are considered in local resource planning and that transmission often is planned as a last resort. Therefore, when local transmission plans are brought together in a regional transmission planning process to determine if a regional solution can better meet the needs of the region than the sum of local transmission plans, many opportunities for the use of alternative resources will already have been considered. Just as there may be opportunities for regional transmission solutions to better meet the needs of the region, the same could be true for regional non-transmission alternatives. However, the regional transmission planning process is not the vehicle by which integrated resource planning is conducted; that may be a separate obligation imposed on many public utility transmission providers and under the purview of the states.

155. While we require the comparable consideration of transmission and non-transmission alternatives in the regional transmission planning process, we will not establish minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives. Those considerations are best managed among the stakeholders and the public utility transmission providers participating in the regional transmission planning process.[147] However, we note that in Order Nos. 890 and 890–A, as well as in orders addressing related compliance filings, we have provided guidance regarding the requirements of the Order No. 890 comparability transmission planning principle.[148] Specifically, public utility transmission providers are required to identify how they will evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis.[149]

156. We disagree with concerns raised by certain commenters that the Order No. 890 comparability transmission planning principle may interfere with integrated resource planning.[150] As discussed above, this Final Rule in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over siting, permitting, or construction of transmission solutions.[151] In addition, on compliance with Order No. 890, each public utility transmission provider already has put into place regional transmission planning processes that provide for the evaluation of proposed solutions on a comparable basis.[152] In this Final Rule, the Commission is applying to regional transmission planning the comparability transmission planning principle stated in Order Nos. 890 and 890–A.[153]

157. We agree with commenters that public utility transmission providers should have flexibility in determining the most appropriate manner to enhance existing regional transmission planning processes to comply with this Final Rule. As a result, and consistent with our approach in Order No. 890, we will not prescribe the exact manner in which public utility transmission providers must fulfill the requirements of complying with the regional transmission planning principles. We allow public utility transmission providers developing the regional transmission planning processes to craft, in consultation with stakeholders, requirements that work for their transmission planning region. Consistent with this approach, we will not impose additional rules that would detail consistent planning cycles, impose stakeholder procedures, establish timelines for evaluating regional transmission projects in the regional transmission planning process (including establishing a minimum long-term planning horizons), add any additional requirements to the Order No. 890 dispute resolution transmission planning principle, or establish other planning criteria beyond those in this Final Rule, as requested by some commenters. These are matters best suited to resolution by the public utility transmission providers and stakeholders in the transmission planning region. We also reject Anbaric and PowerBridge's

[144] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494.

[145] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438.

[146] *Id.* P 454.

[147] We also deny, as beyond the scope of this proceeding, NRG's requests that we direct PJM to determine why its markets are not sending appropriate price signals and that we direct ISOs and RTOs to establish a ''feedback loop.''

[148] *See, e.g.,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 216. *See also, e.g., California Indep. Sys. Operator Corp.,* 123 FERC ¶ 61,283 (2008); *East Kentucky Power Coop.,* 125 FERC ¶ 61,077 (2008).

[149] *See, e.g., NorthWestern Corp.,* 128 FERC ¶ 61,040 at P 38 (2009) (requiring the transmission provider's OATT to permit sponsors of transmission, generation, and demand resources to propose alternative solutions to identified needs and identify how the transmission provider will evaluate competing solutions when determining what facilities will be included in its transmission plan); *El Paso Elec. Co.,* 128 FERC ¶ 61,063 at P 15 (2009) (same); *New York Indep. Sys. Operator, Inc.,* 129 FERC ¶ 61,044, at P 35 (2009) (same). In each of these cases, the Commission stated that tariff language could, for example, state that solutions will be evaluated against each other based on a comparison of their relative economics and effectiveness of performance. Although the particular standard a public utility transmission provider uses to perform this evaluation can vary, the Commission explained that it should be clear from the tariff language how one type of investment would be considered against another and how the public utility transmission provider would choose one resource over another or a competing proposal. *Northwestern Corp.,* 128 FERC ¶ 61,040 at P 38, n.31; *El Paso Elec. Co.,* 128 FERC ¶ 61,063 at P 15, n.25; *New York Indep. Sys. Operator, Inc.,* 129 FERC ¶ 61,044 at P 35, n.26.

[150] *E.g.,* Ad Hoc Coalition of Southeastern Utilities.

[151] *See supra* section III.A.2.

[152] *See, e.g.,* Entergy OATT, Attachment K at § 3.12; Florida Power and Light OATT, Appendix 1 to Attachment K, §§ H and I; ISO New England OATT, Attachment K at § 4.2; Puget Sound Energy OATT, Attachment K at § 2; SPP OATT, Attachment O at § III.8.

[153] *See, e.g., supra* notes 148–49.

suggestion that procedures be developed to treat transmission project information as confidential, outside of the Commission's Critical Energy Infrastructure Information (CEII) requirements and regulations, as this runs counter to the requirement that regional transmission planning processes be open and transparent.

158. Additionally, we note that a public utility transmission provider's regional transmission planning process may utilize a ''top down'' approach, a ''bottom up'' approach, or some other approach so long as the public utility transmission provider complies with the requirements of this Final Rule. Public utility transmission providers have flexibility in developing the necessary enhancements to existing regional transmission planning processes to comply with this Final Rule, based upon the needs and characteristics of their transmission planning region.

159. We also decline to impose obligations to build or mandatory processes to obtain commitments to construct transmission facilities in the regional transmission plan, as requested by some commenters. The package of transmission planning and cost allocation reforms adopted in this Final Rule is designed to increase the likelihood that transmission facilities in regional transmission plans will move from the planning stage to construction. In addition, public utility transmission providers already are required to make available information regarding the status of transmission upgrades identified in transmission plans, including posting appropriate status information on its Web site, consistent with the Commission's CEII requirements and regulations.[154] To the extent an entity has undertaken a commitment to build a transmission facility in a regional transmission plan, that information should be included in such postings.[155] We determine that this obligation, together with the reforms we adopt in this Final Rule, are adequate without placing further obligations on public utility transmission providers.

160. The Commission also acknowledges the importance of identifying the appropriate size and scope of the regions over which regional transmission planning will be performed. We clarify that for purposes of this Final Rule, a transmission planning region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have agreed to participate in for purposes of regional transmission planning and development of a single regional transmission plan. As the Commission explained in Order No. 890, the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.[156] We note that every public utility transmission provider has already included itself in a region for purposes of complying with Order No. 890's regional participation transmission planning principle. We will not prescribe in this Final Rule the geographic scope of any transmission planning region. We believe that these existing regional processes should provide some guidance to public utility transmission providers in formulating transmission planning regions for purposes of complying with this Final Rule. However, to the extent necessary, we clarify that an individual public utility transmission provider cannot, by itself, satisfy the regional transmission planning requirements of either Order No. 890 or this Final Rule.

161. The Commission also clarifies that the obligation to participate in a regional transmission planning process that produces a regional transmission plan that meets the seven transmission planning principles, is not intended to appropriate, supplant, or impede any local transmission planning processes that public utility transmission providers undertake. The objective of this Final Rule is to amend the requirements of Order No. 890 so that regional transmission planning processes not only continue to meet the transmission planning principles established in Order No. 890 but, additionally, produce a regional transmission plan.

162. With regard to comments that seek clarification as to the applicability of the requirements of this Final Rule to transmission projects currently being proposed in existing regional transmission planning processes, we clarify in section II.D above that the requirements of this Final Rule are intended to apply to new transmission facilities. Our intent is to enhance transmission planning processes prospectively to provide greater openness and transparency in the development of regional transmission plans. As also discussed in section II.D above, we recognize that this Final Rule may be issued in the middle of a transmission planning cycle, and we therefore direct public utility transmission providers to explain in their respective compliance filings how they intend to implement the requirements of this Final Rule. In response to comments requesting that the Commission mandate that public utility transmission providers include a funding mechanism to facilitate the participation of in the regional transmission planning process of interested entities that are not market participants, this Final Rule affirms the general approach the Commission took in Order No. 890 regarding the recovery of costs associated with participation in the transmission planning process. There, the Commission acknowledged concerns regarding ''how state regulators and other agencies will recover the costs associated with their participation in the planning process.'' [157] The Commission therefore directed public utility transmission providers to ''propose a mechanism for cost recovery in their planning compliance filings'' and stated that those proposals ''should include relevant cost recovery for state regulators, to the extent requested.'' [158] We decline to expand that directive here to include funding for other stakeholder interests, as requested by certain commenters. However, we also note that, to the extent that public utility transmission providers choose to include a funding mechanism to facilitate the participation of state consumer advocates or other stakeholders in the regional transmission planning process, nothing in this Final Rule precludes them from doing so.

163. With regard to the participation of merchant transmission developers in the regional transmission planning process, we conclude that, because a merchant transmission developer assumes all financial risk for developing its transmission project and constructing the proposed transmission facilities, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of identifying the beneficiaries of its transmission project that would otherwise be the basis for securing eligibility to use a regional cost

[154] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472.

[155] Nothing in this Final Rule limits public utility transmission providers from developing mechanisms to impose an obligation to build transmission facilities in a regional transmission plan, consistent with the requirements below regarding the treatment of nonincumbent transmission developers. Similarly, nothing in this Final Rule preempts or otherwise limits any such obligation that may exist under state or local laws or regulations.

[156] *See, e.g.,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527.

[157] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.339 and P 586.

[158] *Id.* n.339.

allocation method or methods.[159] However, we acknowledge the concern of some commenters that a transmission project proposed or developed by a merchant transmission developer has broader impacts than simply cost recovery. Because all electric systems within an integrated network are electrically connected, the addition or cancellation of a transmission project in one system can affect the nature of power flows within one system or on other systems.

164. We therefore conclude that it is necessary for a merchant transmission developer to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. We will allow public utility transmission providers in each transmission planning region, in consultation with stakeholders, in the first instance to propose what information would be required. Public utility transmission providers should include these requirements in their filings to comply with this Final Rule.

165. Although merchant transmission developers must provide information in the regional transmission planning process as discussed herein, to be clear, we emphasize that the transmission facilities proposed by a merchant transmission developer are not subject to the evaluation and selection processes that apply to transmission facilities for which regional cost allocation is sought, as a merchant transmission developer is not seeking to be selected in the regional transmission plan for purposes of cost allocation. However, nothing in this Final Rule prevents a merchant transmission developer from voluntarily participating in the regional transmission planning process (beyond providing the information and data required above) even if it is not seeking regional cost allocation for its proposed transmission project. As we stated in the Proposed Rule, we encourage them to do so. In addition, nothing in this Final Rule limits or otherwise affects the responsibilities a merchant transmission developer may have to fund network upgrades caused by the interconnection of its project with the transmission grid.[160]

4. Consideration of Transmission Needs Driven by Public Policy Requirements [161]

a. Commission Proposal

166. The Proposed Rule would require that transmission needs driven by Public Policy Requirements be taken into account in the local and regional transmission planning process to ensure that each public utility transmission provider's transmission planning process supports rates, terms, and conditions of transmission service in interstate commerce that are just and reasonable and not unduly discriminatory or preferential. The Proposed Rule would require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements.[162] The Commission noted that this proposed requirement would be a supplement to, and would not replace, any existing requirements with respect to consideration of reliability needs and application of the Order No. 890 economic planning studies transmission planning principle in the transmission planning process.[163] If a public utility transmission provider believes that its existing transmission planning processes satisfy these requirements, then the Proposed Rule would require that the public utility transmission provider must make that demonstration in its compliance filing.[164]

167. The Proposed Rule would require each public utility transmission provider to coordinate with its stakeholders to identify Public Policy Requirements that are appropriate to include in its local and regional transmission planning processes.[165] The Proposed Rule stated that, after consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by state or federal laws or regulations.

168. The Proposed Rule sought comment on how planning criteria based on Public Policy Requirements should be formulated, including whether it would be more appropriate to use flexible criteria rather than ''bright line'' metrics when determining which transmission projects are to be included in a regional transmission plan, whether the use of flexible criteria would provide undue discretion as to whether a transmission project is included in a regional transmission plan, and whether the use of ''bright line'' metrics may inappropriately result in alternating inclusion and exclusion of a single transmission project over successive planning cycles and thus create inappropriate disruptions in long-term transmission planning.[166]

b. Comments

169. In general, most commenters support the Commission's proposal that each public utility transmission provider must amend its OATT such that local and regional transmission planning processes explicitly provide for the consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.[167] Support came from all sectors of the industry,

[159] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 99.

[160] We note that, to the extent a merchant transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it also will be required to comply with all applicable obligations, including registration with NERC. Under section 215, all users, owners, or operators of the bulk power system must register with NERC for performance of applicable reliability functions. The registration with NERC will help ensure that merchant transmission developers provide all appropriate information to be used in transmission system planning and assessment studies. *See* 16 U.S.C. 824o(g) (''Reliability Reports—The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.''); *see also Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204, at P 803, *order on reh'g,* Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006). Concerns regarding when NERC registration would be triggered should be addressed in a NERC registration process.

[161] *See supra* P 2 (defining Public Policy Requirements).

[162] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 64.

[163] *Id.*

[164] *Id.* P 66.

[165] *Id.* P 65.

[166] *Id.* P 70.

[167] *E.g.,* Allegheny Energy Companies; American Transmission; Anbaric and PowerBridge; Arizona Corporation Commission; Arizona Public Service Company; Atlantic Grid; AWEA; California Commissions; California ISO; Clean Energy Group; Connecticut & Rhode Island Commissions; Consolidated Edison and Orange & Rockland; DC Energy; Delaware PSC; Dominion; Duke; Duquesne Light Company; EarthJustice; Exelon; First Wind; Iberdrola Renewables; Integrys; ISO New England; ISO/RTO Council; Maine PUC; Massachusetts Departments; Massachusetts Municipal and New Hampshire Electric; MISO; MISO Transmission Owners; National Audubon Society; National Grid; New England States' Committee on Electricity; New Jersey Board; New Jersey Division of Rate Counsel; New York PSC; NextEra; Northeast Utilities; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Old Dominion; Pacific Gas & Electric; Pattern Transmission; Pennsylvania PUC; PHI Companies; PJM; PUC of Nevada; San Diego Gas & Electric; Southern California Edison; Sunflower and Mid-Kansas; Transmission Dependent Utility Systems; Transmission Access Policy Study Group; Transmission Agency of Northern California; Western Grid Group; and Wind Coalition.

including public utilities, municipal and cooperative utilities, renewable generators, transmission developers, state commissions, and consumer and public interest representatives. While most commenters support the proposal to include public policy requirements in transmission planning processes, a number seek clarification or request that the Commission provide additional guidance.

170. With regard to what constitutes a public policy requirement, some commenters seek to limit the definition to state and federal laws and regulations[168] while others seek a more flexible approach. For example, Omaha Public Power District supports the Commission's proposal only if such public policy requirements are established by state or federal laws or regulations applicable to all entities in the relevant planning region. East Texas Cooperatives believes that Omaha Public Power District's proposal strikes a reasonable balance. Similarly, National Rural Electric Coops state that the Commission should not empower stakeholders to use the transmission planning process to impose and enforce new resource planning requirements that lack the sanction of state or federal law in the planning region. First Energy Service Company argues that only enforceable requirements that are embodied in state or federal law should be eligible for inclusion in transmission planning processes. Duke states that the Final Rule should make unambiguous that the public policy aspect of regional and interregional planning refers only to those transmission projects driven by the need to comply with state and/or federal laws, rules, and/or regulations and that it supports limiting the requirement to public policies that drive the need for transmission.

171. Likewise, PJM states that the Commission should make clear that the responsibility of the transmission planner to plan for public policy criteria is triggered by the clear and formal identification of those public policy criteria identified by Congress or state policymakers through publicly issued laws or regulations and recognize that the transmission planner would need to refer to the states to reconcile conflicting policies that cannot both be reasonably accommodated under a cost-effective and efficient regional transmission plan. In their reply comments, APPA, PSEG Companies, ISO/RTO Council, and Illinois Commerce Commission also caution about transmission planners picking and choosing the public policies that would be considered in transmission planning processes.

172. In their reply comments, ISO/RTO Council suggest that the Final Rule make clear that public policy objectives are limited to those developed by federal or state executive, legislative, and regulatory bodies with authority to adopt such objectives, that ISOs and RTOs may defer to regional state committees on identifying and reconciling individual state public policy goals, that states should utilize the authority under section 216(i) of the FPA to enter into regional compacts to ensure that recommendations pass constitutional muster and otherwise have a suitable legal foundation, and that stakeholders should advocate means of implementing state public policy mandates to the states rather than to ISOs/RTOs.

173. Several comments focus on the role of states in the identification of public policy requirements and what constitutes such a requirement. Many request that the Final Rule expressly acknowledge the role of the state regulatory agencies and governors.[169] For example, PUC of Nevada supports the Commission's concept to require that public policies be incorporated into transmission planning and states that the Final Rule should specify the role state regulatory commissions and governors play in ensuring that the transmission plan accurately reflects state policies and, where there are inconsistencies in the utility's interpretation of the state's public policy versus that of the state regulatory commissions and governors, the Commission should give deference to the regulatory commissions' and governors' interpretation. PUC of Nevada also notes that the Final Rule does not include an oversight mechanism.

174. New England States Committee on Electricity conditions its support for the Commission's proposal on states identifying the policies established in law and regulations to be considered in transmission analysis. New York PSC comments that the Commission should modify the process to allow states to identify which state-level policies should be included in the transmission planning process. It also asks the Commission to clarify that these policies may include public policies derived pursuant to such statutory or regulatory authority, such as those created pursuant to regulatory orders or state energy plans and to allow states to identify state-level policies for inclusion in those plans, not stakeholders. In reply comments, California PUC also states that the Commission should not establish prescriptive criteria regarding what policy goals are to be included. City of Los Angeles Department of Water and Power states that the Commission's proposal should be expanded to include local laws and regulations, noting that many requirements of entities such as itself are grounded in such local mandates.

175. NARUC notes that states will not turn over their policy authority to planning entities for inclusion in a Commission tariff and states that, while it is valuable to have transmission planning processes incorporate public policy considerations, a Commission tariff cannot mandate particular policy approaches. NARUC explains that transmission planners should not be required to determine unwritten public policy requirements, and that the Final Rule should explicitly recognize the governmental role, particularly at the state level, in providing policy input into the transmission planning processes, rather than directing the planners to consult with all stakeholders. NARUC states that the Final Rule should make explicit that any provisions do not impede or interfere with state commission authority to accept or approve integrated resource plans, make decisions about generation, demand-side resources, resource portfolios, or to modify policy based on cost thresholds. East Texas Cooperatives, First Wind, and Florida PSC express their support for NARUC's position.

176. Connecticut & Rhode Island Commissions state that the Commission should not prescribe any particular public policy requirement that must be considered or excluded from the transmission planning process. Moreover, they argue that the states, not transmission utilities and planners, must retain their jurisdiction as the ultimate arbiter on the issue of whether a transmission project is the most beneficial, lowest cost, or most prudent decision for achieving a state public policy goal. North Carolina Agencies assert that the regional transmission planning processes should not decide how to meet state and federal policy requirements, and that the FPA gives the Commission no authority to determine what resources should be used by load-serving entities, regardless of whether or not those resources are

[168] *E.g.,* Omaha Public Power District; Exelon; First Energy Services; PJM; New York ISO; and Transmission Agency of Northern California.

[169] *E.g.,* Connecticut & Rhode Island Commissions; Massachusetts Departments; PUC of Nevada; and New England States Committee on Electricity.

needed to meet public policy requirements.

177. Others seek more flexibility in defining what constitutes a public policy requirement.[170] For example, Pacific Gas & Electric asks that the Final Rule clarify that local and regional transmission planning processes for public utility transmission providers consider state or federal public policy objectives rather than identifying or referring to specific laws and regulations. NextEra seeks clarification that any type of legal or regulatory requirements affecting transmission development should be included in the transmission planning process, noting that the EPA has established a schedule for issuing of a host of Clean Air Act rules governing other emissions from electric generating units. Iberdrola Renewables states that any state and federal renewable portfolio requirements and any state and federal greenhouse gas emission reduction or climate change policies, including requirements or standards that take effect in future years, should be considered in the transmission expansion plan. Atlantic Wind Connection states that the Commission should broaden the phrase ''public policy requirements'' used in the Proposed Rule to include public policy initiatives or something similar to reflect the broad, non-compulsory nature of the policy environment.

178. Several commenters, including some consumer advocates and public interest organizations, recommend that the Commission specify the state and federal policy requirements that utilities, must, at a minimum, take into account in their transmission planning processes.[171] Some suggest including: (1) Renewable portfolio standards; (2) energy efficiency standards and mandates; (3) CO_2 emissions reduction targets/requirements; (4) NAAQS attainment and interstate air pollution reductions; (5) EPA utility sector regulations; and (6) federal and state land management, land use, wildlife conservation and zoning policies and procedures intended to facilitate the siting of renewable energy.[172] In its reply comments, EarthJustice endorses this view. Twenty-six Public Interest Organizations state that comparable consideration of all resource options available to meet various public policy requirements is essential to minimizing utilities' opportunities for undue discrimination. Ohio Consumers' Counsel and West Virginia Consumer Advocate Division state that transmission providers should be required describe the role that each ''public policy'' would play in the transmission planning process. Michigan Citizens Against Rate Excess state that while both reliability and public policy requirements should be considered as part of the same plan, they should be analyzed separately and the transmission plan should explain how these projects may complement or contradict each other.

179. Commenters that believe that the Commission should take a broader view of what public policy requirements are to be considered by transmission providers and their stakeholders, argue, for example, that the transmission planning process must be sufficiently flexible to include reasonably foreseeable public policy objectives not yet explicitly required by existing law or regulation and also to consider ''at risk'' generation.[173] Atlantic Wind Connection suggests the adoption of an unambiguous requirement to plan transmission additions needed to accommodate public policy initiatives and suggests that the Commission require specific tariff provisions describing how transmission facilities that accommodate and facilitate public policy initiatives would be planned for and evaluated. AWEA states that the Commission should clarify that public policy requirements are not to be narrowly construed and that expected future public policy requirements as well as existing ones should be considered.

180. However, in reply, a number of commenters take exception with the suggestion that possible or likely future public policies should be considered in the transmission planning process stating, among other things, that it could result in constantly moving targets, unfocused transmission planning, regulatory uncertainty, and the RTOs or the Commission assuming the roles of Congress and the states.[174] For example, Exelon argues that the Final Rule should specify that planning for public policy should not include aspirational goals. Likewise, Large Public Power Council's reply comments state that transmission planners should not be required to take into account anticipated public policies. Xcel also believes that the requirement to consider public policy directives in developing transmission plans should focus on established policies, rather than anticipated or potential future obligations.

181. Among those seeking flexibility and recognition of regional differences,[175] Edison Electric Institute and Northeast Utilities state that the Commission should allow flexibility in defining the types of public policy requirements; determining implementation details, such as the process to identify public policy requirements; and how transmission system needs would be selected once an appropriate public policy requirement is identified. Northern Tier Transmission Group states that to the extent that a transmission provider maintains an obligation to serve retail load, its merchant/load-serving function will identify and quantify the relevant public policy requirements, which will then be accounted for in its local transmission plan. Any additional public policy objectives should be at the discretion of regional planning groups. Transmission Access Policy Study Group states that the Final Rule should clarify the reference to state and federal policy requirements, so that it includes state regulatory commission orders and regulations and local governmental mandates on load-serving entities; and expressly identify FPA section 217(b)(4) as a federal public policy requirement that the regional transmission planning process must consider.

182. Other commenters have ideas on or questions about how public policy requirements are to be included and implemented. Exelon states that the Commission should adopt principles to help head off stalemates: (1) Transmission planning must include likely retirements of plants subject to environmental regulations; (2) encompass only laws actually in effect in determining the impact on generation capacity; (3) require transmission planners to take into account all the actual terms of state and federal laws and regulations for which transmission expansion is planned; (4) require a region to show that its stakeholder-endorsed policy would not cause any harm or costs to other regions; (5) the full cost of resources must be transparent and considered in the transmission planning process, based on

[170] *E.g.,* New Jersey Division of Rate Counsel and Integrys.

[171] *E.g.,* EarthJustice; 26 Public Interest Organizations; and National Audubon Society.

[172] *E.g.,* Conservation Law Foundation; Energy Future Coalition Group; E.ON Climate & Renewables North America; Environmental Defense Fund; Environmental NGOs; Natural Resources Defense Council; Sonoran Institute; and Wilderness Society and Western Resource Advocates.

[173] *E.g.,* Iberdrola Renewables.

[174] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Coalition for Fair Transmission Policy; East Texas Cooperatives; Large Public Power Council; National Rural Electric Coops; and New England States Committee on Electricity.

[175] *E.g.,* ISO/RTO Council; ISO New England; PJM; New York ISO; SPP; MISO; New York Transmission Owners; NEPOOL; and MISO Transmission Owners.

sound economic principles; and (6) require that planning for renewable energy resources be done with the objective of minimizing total costs. MISO states that the proposal should be expanded to include a requirement to, when prudent, pursue appropriate transmission expansion initiatives to facilitate the compliance of public policy requirements by entities within the transmission provider's footprint that are subject to such requirements.

183. PJM states that the actual development of transmission to address public policy standards requires: (1) Further direction as to how such standards should be reflected in implementable planning assumptions; and (2) a legally empowered coordination among states with shared policy agendas allowing regional projects to be sited and permitted because they are ''needed'' to meet the multistate collective's shared policy agenda. Old Dominion and Atlantic Wind Connection support PJM's suggested holistic approach to transmission planning. In response, however, Consolidated Edison and Orange & Rockland argue that PJM's comments do not adequately reflect the Proposed Rule's objective to respect regional methods and urge the Commission to reject PJM's top down approach.

184. Pattern Transmission states that the Commission should require public utility transmission providers to specify when transmission upgrade projects are categorized as public policy-driven projects and when the transmission facilities are considered solely through the generator interconnection process.

185. Others offer for Commission consideration their desired outcomes from including Public Policy Requirements in regional transmission planning.[176] For example, Transmission Agency of Northern California seeks confirmation that simply characterizing a project's purpose as meeting a public policy requirement should not provide that project a presumption of inclusion in the regional transmission planning process. Transmission Access Policy Study Group states that the Commission should urge transmission providers to adopt a ''no regrets'' strategy that focuses on constructing transmission facilities needed under multiple potential power supply and public policy scenarios, which lead to a ''right-sized'' grid with greater flexibility to respond to changing technology, resource options, and customer needs. Old Dominion also asks that the Final Rule make clear that the directive to plan for public policy laws or regulations is for transmission planning only, not for design and construction or to improve power supply.

186. Western Grid Group states that, at a minimum, the Commission should require regional plans to address a planning horizon of at least 20 years and to evaluate environmental and economic constraints and public interest concerns over that horizon as a basis for the development of such plans. Powerex cautions that the consideration of public policy factors not result in transmission planning and cost allocation processes that elevate the needs of certain customers over others in the transmission planning process and should preserve competitive wholesale power markets.

187. Commenters also offer ideas on timing and scope. Some commenters argue that only federal and state laws and regulations in effect during the transmission planning cycle should be considered as public policy requirements in the regional transmission planning process.[177] East Texas Cooperatives, however, believes that a better approach is to let participants in the transmission planning process advocate for their own needs and interests (which by necessity will reflect the need to comply with policies contained in applicable federal and state law), and then allow the transmission planning process to sort out these interests within the existing Order No. 890 transmission planning framework. In response to such comments, however, AEP contends that planning for only current regulatory requirements is too narrow a formulation that would result in underinvestment in transmission infrastructure. AEP suggests that the transmission planning process consider reasonably foreseeable future regulatory requirements given their likely impact on the power system, citing NERC's analysis of potential impacts of EPA regulations on generation.

188. A number of commenters believe either that existing regional transmission planning processes already consider public policy requirements and thus OATT revisions may therefore be unnecessary.[178] East Texas Cooperatives state that they agree with the Commission's preliminary finding, but disagree as to the need for any revisions to the OATT as transmission planning already takes into account public policy requirements established by state or federal laws or regulations in accordance with Order No. 890's transmission planning requirements, as well as with Commission policy that has evolved over the years. Many commenters in ISO and RTO regions argue that the transmission planning processes administered by those entities already address or largely address public policy issues.[179] For example, New York ISO supports the Commission's proposal but states that existing transmission planning rules already provide for consideration of public policy requirements in many regions. Transmission Dependent Utility Systems recommend that the Commission clarify that nothing in the existing *pro forma* OATT prohibits the consideration of public policy requirements in the transmission planning processes and, to the extent a transmission provider believes its particular OATT does preclude such considerations, the Final Rule should direct compliance filings to remove the language allegedly prohibiting such consideration.

189. Some commenters raise additional concerns, including how public policy considerations would be incorporated into a transmission provider's local and regional transmission planning process including whether the proposal is intended to modify or incorporate generator interconnection requests into the ''local and regional transmission planning process;'' whether a project proposed to satisfy transmission needs driven by public policy requirements are to be planned for and considered separately from reliability and economic projects; whether regional transmission planning organizations are required to create a separate category of public policy-driven transmission projects or whether they are to be in concert with reliability and economic criteria during the transmission planning process.[180]

190. Coalition for Fair Transmission Policy is concerned that the Proposed Rule might be interpreted as requiring transmission planning processes to make decisions as to how best to meet applicable public policy requirements on behalf of those entities on whom the

[176] *E.g.,* Pattern Transmission; Transmission Agency of Northern California; and Transmission Access Policy Study Group.

[177] *E.g.,* National Rural Electric Coops; City of Santa Clara; Michigan Citizens Against Rate Excess; Exelon; East Texas Cooperatives; and Coalition for Fair Transmission Policy.

[178] *E.g.,* Washington Utilities and Transportation Commission; Alliant Energy; Xcel; Bonneville Power; Westar; Sacramento Municipal Utility District; National Rural Electric Coops; East Texas Cooperatives; WECC; WestConnect; Georgia Transmission Corporation; Southern Companies; and Ad Hoc Coalition of Southeastern Utilities.

[179] *E.g.,* New England Transmission Owners; Alliant Energy; and New York ISO.

[180] *E.g.,* NV Energy; Long Island Power Authority; and Bonneville Power.

requirements are placed. Therefore, it states that decisions on how load-serving entities within regions should meet state or federal public policy requirements should continue to be made by those with responsibilities to meet the requirements, based on federal and state law and applicable regulations, and recommends that the Final Rule make this clear.

191. PPL Companies state that basing transmission planning decisions on state public policy directives may lead to undue discrimination among generators and, thus, run afoul of the FPA requirement that all users of the transmission system be treated in a non-discriminatory manner. It states that the Commission should direct transmission planners to make sure that pre-existing rights are preserved and accommodated under the Proposed Rule's transmission planning principles, just as the Commission preserved grandfathered transmission contracts under Order No. 888 and grandfathered interconnection agreements under Order No. 2000.

192. New Jersey Board believes there needs to be recognition of planning for public policy goals in terms of reliability. It asserts that focusing solely on public policy goals as the driving force in the transmission planning process would raise issues as to which policy should receive the greatest emphasis, and would cause conflict in the transmission planning process over which goals to incorporate. New Jersey Board recommends that transmission plans incorporate public policy goals in a fashion that has these projects evaluated similarly for reliability and economic purposes.

193. Some commenters generally oppose the proposal to require public policy considerations in transmission planning.[181] PSEG Companies state that the Commission's public policy planning approach should not be adopted, arguing that the proposal would result in public utility transmission providers establishing an unduly preferential practice favoring renewable energy resources over other types of resources. Finally, PSEG Companies are concerned that the proposal could result in overbuilding or underbuilding the transmission grid. Ad Hoc Coalition of Southeastern Utilities asserts that there is no dependable means to translate abstract notions of public policy into the transmission planning process, except to the extent it has a bearing on transmission demand. Energy Consulting Group states that interregional planning should not be used as an instrument of public policy but should incent development of transmission improvements to afford the public access to all types of generation that is economic and minimizes its power costs. APPA believes that any transmission provider wishing to incorporate specific state policy requirements or other objectives into its transmission planning protocols should do so through case-by-case tariff filings under FPA section 205.

194. Electricity Consumers Resource Council and the Associated Industrial Groups are concerned with mandatory interjection of state public policy considerations into the transmission planning process and how, in practice, this is expected to work, given public policy differences among states, and they are concerned that the Proposed Rule delegates to ISOs and RTOs the authority to impose the public policy requirements of one state on another without sufficient democratic or procedural checks and balances.

195. Some commenters agree with the proposal to coordinate identification of public policy requirements. These commenters generally state that flexibility is needed given the regional variation in: public policy objectives; types and location of resources; and regional needs, provided that transmission providers seek input from state authorities and other stakeholders.[182] MISO Transmission Owners ask that the Commission not mandate what public policy requirements must be considered, but should allow individual transmission providers to work with stakeholders to identify public policy requirements applicable to the state(s) or region in which the transmission provider is located; they also state that transmission planning regions should not be required to plan for or contribute to the costs of enabling compliance with public policy requirements enacted outside of their region without the agreement of all regions affected.

196. Some commenters agree that public utility transmission providers should be required to specify the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements. 26 Public Interest Organizations assert that the Commission should require all transmission providers to incorporate certain best practices in the OATT to achieve the Commission's goal. These include: (1) Minimum coordination agreement requirements for plan development; (2) required actions to assure robust participation in regional plan development by non-market participant stakeholders; and (3) minimum requirements to ensure fair and comparable consideration of all options to meet public policy requirements. Clean Energy Group states that transmission planners should be required to identify the specific public policy goals that would be considered in the planning cycle after consultation with stakeholders, including state policy makers. Additionally, it states that transmission providers should be required to disclose and document how public policy considerations were taken into account.

197. Other commenters would like flexibility in this regard. Edison Electric Institute states that the Commission should not require transmission providers to identify in their tariff each specific public policy requirement that may be taken into consideration but should allow flexibility. ISO New England and Kansas City Power & Light and KCP&L Greater Missouri similarly argue that the Commission should specify that it would not become a requirement within the tariff to list each specific public policy requirement. However, in reply, Conservation Law Foundation argues that the policies should be reflected in the OATT and asks that the Final Rule hold planning authorities responsible for applying those policies that are germane to a given process or decision. In their reply comments, Maine Parties point to MISO tariff provisions that show that ISOs and RTOs can develop tariff provisions that include criteria for identifying public policy projects, and request that the Commission be explicit about the role it expects ISOs and RTOs to play in identifying state and federal public policies and in identifying criteria for selecting projects.

198. In response to the Commission's question regarding the use of ''bright line'' metrics when evaluating potential transmission projects, the majority of commenters that provided input on this issue support a flexible approach.[183]

[181] *E.g.,* PSEG Companies; First Energy Service Company; Ad Hoc Coalition of Southeastern Utilities; National Rural Electric Coops; Southern Companies; Large Public Power Council; Nebraska Public Power District; and Long Island Power Authority.

[182] *E.g.,* American Transmission; Atlantic Grid; Consolidated Edison and Orange & Rockland; Edison Electric Institute; Energy Consulting Group; MISO Transmission Owners; NEPOOL; New England Transmission Owners; New York Transmission Owners; and Northeast Utilities.

[183] *E.g.,* Anbaric and PowerBridge; Atlantic Grid; AWEA; First Wind; Integrys; National Rural Electric Coops; New Jersey Division of Rate Counsel; New York ISO; New York Transmission Owners; NextEra; Northeast Utilities; Northern Tier Transmission Group; Organization of MISO States; PJM; SPP; WECC; and Westar.

They generally agree that transmission providers should be provided flexibility to take into account the multiple reliability, economic, and public policy-based benefits a single project may provide. They express concern that projects that address reliability, economic, and public policy initiatives may not be pursued because the transmission provider may not be allowed to include the project in the regional plan because of the technical failure to meet a bright line test. AWEA notes that existing transmission planning processes that rely on bright line criteria do not accommodate well the integration of renewable resources into the grid. NRECA states that bright line metrics are unnecessary because load-serving entities' planning requirements implicitly include established public policy requirements.

199. While expressing the need for flexibility, some commenters note that the Commission should establish in the Final Rule some level of specificity as to how the regional plan should consider projects designed to meet public policy requirements. NEPOOL suggests that the Commission grant deference to the states in a planning region with regard to how they would want public policy requirements to be considered in the context of regional planning. SPP echoes this, stating that the Commission should afford transmission providers, state regulatory commissions, and stakeholders flexibility to develop strategies and metrics that appropriately consider the needs and reflect the existing structure of the transmission system in the region. First Wind recognizes that certain public policy considerations could require a bright line metric to ensure they be included in a regional plan, while others could be more general and flexible.

200. Others, however, argue that bright line metrics are necessary to avoid discrimination in the transmission planning process.[184] City and County of San Francisco and LS Power both assert that removing bright line criteria would lead to unfair results. City and County of San Francisco assert that without bright line criteria, end-users could be penalized because of different cost allocation methods associated with each distinct criterion.

201. Some commenters support a balanced approach of using both bright line and flexible metrics. While Organization of MISO States cautions against the establishment of rigid bright line metrics, it notes that an overly flexible approach could allow for higher cost projects than are actually needed. It states that the Commission should seek a reasonable balance by ordering transmission planners to start with defined criteria and then look further into more flexible options that could provide an optimal solution to a number of perceived needs. Dominion states that both flexible and bright line criteria may be needed for some multi-purpose projects. Dominion explains that the benefit of reliability projects must be assessed against bright line criteria. However, when considering other benefits, Dominion states that more flexibility is needed. Minnesota PUC and Minnesota Office of Energy Security recommend that bright line metrics be used as a first pass in the transmission planning process, but more flexible criteria could be used to assess each project further.

202. Finally, there are some commenters that argue that the Commission's proposal may lead to undesirable outcomes. Large Public Power Council states that requiring each public utility transmission provider to coordinate with customers and other stakeholders to identify relevant state and federal laws and regulations would be unnecessary, potentially confusing, and ultimately counterproductive. Long Island Power Authority states that the Proposed Rule did not identify how a regional transmission planning group encompassing multiple states is to decide which state's ''public policy requirements'' must be satisfied through the transmission planning process. It expresses concern that the apparent default solution of incorporating every state's public policy requirements into the transmission planning process to the extent feasible, may distort the transmission planning process, lead to over-construction of transmission facilities and consequently increase the costs to be allocated. Nebraska Public Power District states that the discretion that this approach would interject into the transmission planning process would seem to be an open door to potential discrimination, and a nightmare to enforce, as parties debate whether planning adequately responds to a variety of potentially competing policies.

c. Commission Determination

203. The Commission requires public utility transmission providers to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[185] As discussed in section II above, the reforms adopted below are intended to ensure that the local and regional transmission planning processes support the development of more efficient or cost-effective transmission facilities to meet the transmission needs driven by Public Policy Requirements, which will help ensure that the rates, terms and conditions of jurisdictional service are just and reasonable. Moreover, these reforms will remedy opportunities for undue discrimination by requiring public utility transmission providers to have in place processes that provide all stakeholders the opportunity to provide input into what they believe are transmission needs driven by Public Policy Requirements, rather than the public utility transmission provider planning only for its own needs or the needs of its native load customers. Our decision here to require transmission planning to include the consideration of transmission needs driven by Public Policy Requirements is supported by the numerous commenters who generally agree with the proposed reforms.[186]

204. Under the existing requirements of Order No. 890, there is no affirmative obligation placed on public utility transmission providers to consider in the transmission planning process the effect that Public Policy Requirements may have on local and regional transmission needs.[187] We agree with

[184] *E.g.,* City and County of San Francisco; LS Power; New Jersey Division of Rate Counsel; and Western Independent Transmission Group.

[185] To the extent public utility transmission providers within a region do not engage in local transmission planning, such as in some ISO/RTO regions, the requirements of this Final Rule with regard to Public Policy Requirements apply only to the regional transmission planning process.

[186] *E.g.,* Allegheny Energy Companies; American Transmission; Anbaric and PowerBridge; Arizona Corporation Commission; Arizona Public Service Company; Atlantic Grid; AWEA; California Commissions; California ISO; Clean Energy Group; Connecticut & Rhode Island Commissions; Consolidated Edison and Orange & Rockland; DC Energy; Delaware PSC; Dominion; Duke; Duquesne Light Company; EarthJustice; Exelon; First Wind; Iberdrola Renewables; Integrys; ISO New England; ISO/RTO Council; Maine PUC; Massachusetts Departments; Massachusetts Municipal and New Hampshire Electric; MISO; MISO Transmission Owners; National Audubon Society; National Grid; New England States' Committee on Electricity; New Jersey Board; New Jersey Division of Rate Counsel; New York PSC; NextEra; Northeast Utilities; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Old Dominion; Pacific Gas & Electric; Pattern Transmission; Pennsylvania PUC; PHI Companies; PJM; PUC of Nevada; San Diego Gas & Electric; Southern California Edison; Sunflower and Mid-Kansas; Transmission Dependent Utility Systems; Transmission Access Policy Study Group; Transmission Agency of Northern California; Western Grid Group; and Wind Coalition.

[187] In response to Transmission Dependent Utility Systems, we note that nothing in the existing *pro forma* OATT affirmatively prohibits consideration

the concerns of many commenters that, without having in place procedures to consider transmission needs driven by Public Policy Requirements, the needs of wholesale customers may not be accurately identified.[188] While we understand that some public utility transmission providers already do have processes in place to determine whether transmission needs reflect Public Policy Requirements, others do not. We correct this deficiency through the requirements below, which are intended to enhance, rather than replace, existing transmission planning obligations under Order No. 890. Moreover, as with other reforms adopted in this Final Rule, these requirements are intended to be an additional set of minimum obligations for public utility transmission providers and are not intended to preclude additional transmission planning related activities.

205. In response to commenters seeking greater clarity as to how transmission needs driven by Public Policy Requirements must be considered by public utility transmission providers, we clarify that by considering transmission needs driven by Public Policy Requirements, we mean: (1) The identification of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions to meet those needs. We therefore direct public utility transmission providers to amend their OATTs to describe the procedures by which transmission needs driven by Public Policy Requirements will be identified in the local and regional transmission planning processes and how potential solutions to the identified transmission needs will be evaluated in the local and regional transmission planning processes. We discuss each of these requirements in turn.

206. First, public utility transmission providers must establish, in consultation with stakeholders, procedures under which public utility transmission providers and stakeholders will identify those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated. Various commenters express concern that a public utility transmission provider should not have an open-ended obligation to undertake costly and time-consuming studies to evaluate the potential impact that every Public Policy Requirement might have on transmission development. As noted by Connecticut & Rhode Island Commissions, for example, entities subject to particular requirements may intend to meet them in ways that do not involve the planning of transmission within the local or regional transmission planning processes. In other circumstances, there may be disagreement among the various entities subject to competing Public Policy Requirements as to whether it is appropriate to consider the impact of complying with those laws and regulations in the transmission planning process.

207. We do not in this Final Rule require the identification of any particular transmission need driven by any particular Public Policy Requirements. Instead, we require each public utility transmission provider to establish procedures for identifying those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated in the local or regional transmission planning processes. As part of the process for identifying transmission needs driven by Public Policy Requirements, such procedures must allow stakeholders an opportunity to provide input, and offer proposals regarding the transmission needs they believe are driven by Public Policy Requirements. To the extent such procedures identify no transmission needs driven by a Public Policy Requirement, the relevant public utility transmission providers are under no obligation to evaluate potential transmission solutions.

208. We allow for local and regional flexibility in designing the procedures for identifying the transmission needs driven by Public Policy Requirements for which potential solutions will be evaluated in the local or regional transmission planning processes. The effects of Public Policy Requirements on transmission needs are highly variable based on geography, existing resources, and transmission constraints. We therefore conclude that it is appropriate to require public utility transmission providers, in consultation with their stakeholders, to design the appropriate procedures for identifying and evaluating the transmission needs that are driven by Public Policy Requirements in their area, subject to our review on compliance. At a minimum, however, we require that all such procedures allow for input from stakeholders, including but not limited to those responsible for complying with the Public Policy Requirement(s) at issue and developers of potential transmission facilities that are needed to comply with one or more Public Policy Requirements.

209. We decline to require that transmission needs driven by Public Policy Requirements be identified by a particular entity or subset of stakeholders. However, all stakeholders must have an opportunity to provide input and offer proposals regarding the transmission needs they believe should be so identified, as discussed above. In other words, while the procedures adopted by public utility transmission providers in response to this Final Rule must allow all stakeholders to bring forth any transmission needs they believe are driven by Public Policy Requirements, those procedures must also establish a just and reasonable and not unduly discriminatory process through which public utility transmission providers will identify, out of this larger set of needs, those needs for which transmission solutions will be evaluated. Some public utility transmission providers might conclude, in consultation with stakeholders, to develop procedures that rely on a committee of load-serving entities, a committee of state regulators, or a stakeholder group to identify those transmission needs for which potential solutions will be evaluated in the transmission planning processes.[189] Another example would be the case where a public utility transmission provider identifies such transmission needs itself on behalf of its customers, following consultation with stakeholders, including participating state regulators. However, to ensure that requests to include transmission needs are reviewed in a fair and non-discriminatory manner, we require public utility transmission providers to post on their Web sites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated. We conclude that this posting requirement is necessary to provide the Commission and interested parties with information as to how the identification procedures are

of the effect of Public Policy Requirements on transmission needs.

[188] *E.g.,* National Grid; NextEra; AWEA; Atlantic Grid; Delaware PSC; Anbaric and PowerBridge; and Conservation Law Foundation.

[189] As noted below, we strongly encourage states to participate actively in the identification of transmission needs driven by Public Policy Requirements. Public utility transmission providers, for example, could rely on committees of state regulators or, with appropriate approval from Congress, compacts between interested states to identify transmission needs driven by Public Policy Requirements for the public utility transmission providers to evaluate in the transmission planning process.

implemented by public utility transmission providers.

210. We decline in this Final Rule to require the identification of any particular set of transmission needs driven by any particular Public Policy Requirements in the local and regional transmission planning processes of public utility transmission providers. To the extent that implementation of the procedures required here results in a suggested transmission need not being evaluated for potential solutions in the local or regional transmission planning process, the relevant public utility transmission provider(s) are under no obligation under this Final Rule to evaluate the potential effect of the associated Public Policy Requirement on transmission development. This includes proposals to evaluate the need for particular transmission facilities proposed by transmission developers to comply with Public Policy Requirements. While these entities may continue to offer their proposed transmission facilities in the local or regional transmission planning process as a potential solution to transmission needs, such proposals would not be evaluated in the transmission planning process as driven by a Public Policy Requirement.

211. With regard to the evaluation of potential solutions to the identified transmission needs driven by Public Policy Requirements, we again leave to public utility transmission providers to determine, in consultation with stakeholders, the procedures for how such evaluations will be undertaken, subject to the Commission's review on compliance and with the objective of meeting the identified transmission needs more efficiently and cost-effectively.[190] As noted in our discussion of regional transmission planning in section III.A above, there are many ways potential upgrades to the transmission system can be evaluated, ranging from the use of scenario analyses to production cost or power flow simulations. At a minimum, however, this process must include the evaluation of proposals by stakeholders for transmission facilities proposed to satisfy an identified transmission need driven by Public Policy Requirements.[191] However, as with any proposed solution offered in the local or regional transmission planning processes for transmission needs driven by reliability issues or economic considerations, there is no assurance that any proposed transmission facility will be found to be an efficient or cost-effective solution to meet local or regional needs.

212. In response to commenters that urge us to recognize the role of the states in transmission planning, especially as it relates to compliance with Public Policy Requirements, we clarify that nothing in this Final Rule is intended to alter the role of states in that regard. Through this Final Rule, we are requiring public utility transmission providers to provide an opportunity to all stakeholders, including state regulatory authorities, to provide input on those transmission needs they believe are driven by Public Policy Requirements, to the extent they are not already doing so. We are not dictating any substantive result with regard to compliance with Public Policy Requirements. In Order No. 890, the Commission stated its expectation that ''all transmission providers will respect states' concerns'' when engaging in the regional transmission planning process.[192] This is equally true with regard to the consideration of transmission needs driven by Public Policy Requirements. We strongly encourage states to participate actively in both the identification of transmission needs driven by Public Policy Requirements and the evaluation of potential solutions to the identified needs.

213. We therefore do not believe our reforms are inconsistent with state authority with respect to integrated resource planning, as suggested by some commenters. Indeed, we believe that the requirements imposed herein complement state efforts by helping to ensure that potential solutions to identified transmission needs driven by Public Policy Requirements of the states can be evaluated in local and regional transmission planning processes. To be clear, however, while a public utility transmission provider is required under this Final Rule to evaluate in its local and regional transmission planning processes those identified transmission needs driven by Public Policy Requirements, that obligation does not establish an independent requirement to satisfy such Public Policy Requirements. In other words, the requirements established herein do not convert a failure of a public utility transmission provider to comply with a Public Policy Requirement established under state law into a violation of its OATT.

214. We do not require public utility transmission providers to consider in the local and regional transmission planning processes any transmission needs that go beyond those driven by state or federal laws or regulations or to specify additional public policy principles or public policy objectives as some commenters have suggested. Based on the record before us, we believe it is sufficient to ensure just and reasonable rates and to avoid the potential for undue discrimination to restrict the requirement for public policy consideration to state or federal laws or regulations that drive transmission needs. Likewise, we will not require restrictions on the type or number of Public Policy Requirements to be considered as long as any such requirements arise from state or federal laws or regulations that drive transmission needs and as long as the requirements of the procedures required herein are met.

215. Some commenters request that we specify EPA regulations or FPA section 217 as Public Policy Requirements driving potential transmission needs relevant for consideration in the transmission planning process. While we decline to mandate the consideration of transmission needs driven by any *particular* Public Policy Requirement, we intend that the procedures required above be flexible enough to allow for stakeholders to suggest consideration of transmissions needs driven by any Public Policy Requirement, including potential consideration of requirements under EPA regulations, FPA section 217, or any other federal or state law or regulation that drive transmission needs. Because we are not mandating the consideration of any particular transmission need driven by a Public Policy Requirement, we disagree with PSEG Companies that we are favoring renewable energy resources over other types of resources.

216. We reiterate here and clarify a statement of the Proposed Rule that generated significant comment; that is, this Final Rule does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by

[190] To the extent a public utility transmission provider determines that existing provisions of its OATT must be amended in order to implement its evaluation process, it may include such tariff revisions in its compliance filing. For example, evaluation of transmission needs driven by a particular Public Policy Requirement could require the gathering of additional information from interconnected generators regarding retirements or from network customers regarding resource preferences.

[191] This requirement is consistent with the existing requirements of Order Nos. 890 and 890–A which permit sponsors of transmission and non-transmission solutions to propose alternatives to identified needs. *See supra* note 149.

[192] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.

state or federal laws or regulations.[193] By providing this clarification, we are neither affirmatively granting new rights to nor imposing an obligation on a public utility transmission provider. Instead, the statement is a recognition that a public utility transmission provider has, and has always had, the ability to plan for any transmission system needs that it foresees. Our recognition of this ability is not intended to limit or expand in any way the option that a public utility transmission provider has always had to plan for facilities that it believes are needed if it chooses to do so. We believe that public utility transmission providers, in consultation with stakeholders, are in the best position to determine whether to consider in a transmission planning process any public policy objectives beyond those required by this Final Rule. We reiterate that this Final Rule creates no obligation for any public utility transmission provider or its transmission planning processes to consider transmission needs driven by a public policy objective that is not specifically required by state or federal laws or regulations. If public utility transmission providers, in consultation with stakeholders, do identify public policy objectives not specifically required by state or federal laws or regulations, we note that transmission facilities designed to meet these objectives may be eligible for cost allocation under the transmission planning process.

217. We note that identifying a set of transmission needs and projects for inclusion in a transmission planning study does not ensure that any particular transmission project will be in the regional transmission plan. Alternative solutions to the identified needs may prove better from cost, siting, or other perspectives. Similarly, elimination of a transmission project or need from the transmission planning process would not prevent any planner or developer from independently seeking to satisfy the need or develop the transmission project, but any resulting transmission facility would not be eligible for cost allocation under a regional cost allocation method or methods required under this Final Rule.

218. Some commenters have expressed concerns that the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process will result in costs being assigned to regions that do not benefit from those requirements or to regions that did not create the need for new transmission. We understand these commenters to be concerned that a requirement to consider transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes will result in cross-subsidization of the costs of meeting Public Policy Requirements.

219. We clarify that any such consideration of transmission needs driven by Public Policy Requirements, to the extent that it results in new transmission costs, must follow the cost allocation principles discussed separately herein.[194] Particularly, the costs of new transmission facilities allocated within the planning region must be allocated within the region in a manner that is at least roughly commensurate with estimated benefits.[195] Those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities. That is, a utility or other entity that receives no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities.

220. Further, we are not requiring that a separate class of transmission projects be created in the transmission planning process related to compliance with Public Policy Requirements, although nothing in this Final Rule prohibits the development of a separate class of transmission projects if the public utility transmission provider and its stakeholders believe that it is appropriate to do so. Some public utility transmission providers might comply with this Final Rule by implementing procedures to consider transmission needs driven by Public Policy Requirements separately from transmission addressing reliability needs or economic considerations. Other public utility transmission providers might comply with this Final Rule by identifying and evaluating all transmission needs, whether driven by Public Policy Requirements, compliance with reliability criteria, or economic considerations. While we provide flexibility for public utility transmission providers to develop procedures appropriate for their local and regional transmission planning processes, we reiterate that all stakeholders must be provided an opportunity to provide input during the identification of transmission needs driven by Public Policy Requirements and the evaluation of potential solutions to the identified needs, as discussed above.

221. In response to Northern Tier Transmission Group, we understand that a public utility transmission provider with a native load obligation may already have addressed compliance with Public Policy Requirements in developing its resource assumptions to be used in the transmission planning process. In such circumstances, the procedures used to identify transmission needs driven by Public Policy Requirements should take that into account. Similarly, the evaluation of potential solutions to those transmission needs identified in a local or regional transmission planning process should reflect the resource decisions of the transmission planning process.

222. The Proposed Rule stated that, if a public utility transmission provider believes that its existing transmission planning process already meets the requirements to consider Public Policy Requirements, then it may make that demonstration in compliance with the Final Rule.[196] Certain commenters question the need for these requirements altogether because they assert they are already obligated to follow all state or federal laws or regulations, including laws or regulations related to public policy objectives. Other commenters, particularly those in ISO and RTO regions, assert that the transmission planning processes administered by those entities already address public policy issues so their compliance obligation should be minimal. In this Final Rule, the Commission is expanding the requirements of the *pro forma* OATT to require that transmission planning processes affirmatively consider transmission needs driven by Public Policy Requirements. Each public utility transmission provider will have the opportunity to demonstrate compliance with these requirements by specifying the procedures in its local and regional transmission planning processes, whether existing or new, for identifying transmission needs driven by Public Policy Requirements and for evaluating potential solutions to meet those identified needs. As with other requirements of this Final Rule, we

[193] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 64. For example, a public utility transmission provider and its stakeholders are not precluded under this Final Rule from choosing to plan for state public policy goals that have not yet been codified into state law, which they nonetheless consider to be important long-term planning considerations.

[194] *See* discussion *infra* section IV.

[195] *See* discussion *infra* section IV.E.2.

[196] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 66.

decline here to prejudge any compliance filings or predetermine whether any public utility transmission provider may already be in compliance.

223. Finally, we considered the many comments on whether it is more appropriate to use flexible criteria in lieu of ''bright line'' metrics when determining which transmission projects are in the regional transmission plan. While we have in the past required adoption of a formulaic approach to applying such metrics,[197] we sought comment on this issue in the Proposed Rule to gain insight as to whether such a formulaic approach was appropriate or if providing additional flexibility was a more effective approach. Our review of the comments suggests that most commenters prefer flexible planning criteria for identifying transmission needs not only driven by Public Policy Requirements and evaluation of solutions to those identified needs, but also for the identification and evaluation of transmission needs related to reliability issues and economic considerations as well.[198] These commenters have convinced us that, although there are benefits to each kind of planning criteria, there is merit in allowing for flexible planning criteria to mitigate the possibility that bright line metrics may exclude certain transmission projects from long-term transmission planning.

224. Hence, we will permit public utility transmission providers to include within their compliance filings in response to this Final Rule any tariff revisions they believe necessary to implement flexible transmission planning criteria, including changes to existing bright line criteria. This could include procedures to address alternating inclusion and exclusion of a single transmission project in a regional transmission plan over successive planning cycles. Because such tariff revisions will be included as part of the compliance filings in response to this Final Rule, they will be submitted pursuant to section 206 of the FPA rather than under section 205. However, those with existing bright line criteria are not required to make this change if they do not wish to do so. As we evaluate the compliance filings to this Final Rule, we also will evaluate both bright line and flexible criteria for whether they permit unjust and unreasonable rates or undue discrimination through planning criteria and whether they will ensure fair consideration of transmission needs driven by Public Policy Requirements as well as by reliability needs and economic considerations.

[197] *See, e.g., PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 (2007).

[198] *E.g.,* AWEA; PJM; New York ISO; SPP; WECC; and Westar.

B. Nonincumbent Transmission Developers

225. This part of the Final Rule addresses the removal from Commission-jurisdictional tariffs and agreements of provisions that grant a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. To implement the elimination of such rights, we adopt below a framework that requires the development of qualification criteria and protocols to govern the submission and evaluation of proposals for transmission facilities to be evaluated in the regional transmission planning process. We further require that any nonincumbent developer of a transmission facility selected in the regional transmission plan have an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods. For purposes of this Final Rule, ''nonincumbent transmission developer'' refers to two categories of transmission developer: (1) A transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, and as we explained in the Proposed Rule, an ''incumbent transmission developer/provider'' is an entity that develops a transmission project within its own retail distribution service territory or footprint.[199]

226. We conclude these reforms are necessary in order to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable, or otherwise result in undue discrimination by public utility transmission providers. As discussed in detail below, our focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation, and not on transmission facilities included in local transmission plans that are merely ''rolled up'' and listed in a regional transmission plan without going through a needs analysis at the regional level (and therefore, not eligible for regional cost allocation). Similarly, our reforms are not intended to affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, nor to alter an incumbent transmission provider's use and control of an existing right of way.

[199] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.23.

227. In developing the framework below, we have sought to provide flexibility for public utility transmission providers in each region to propose, in consultation with stakeholders, how best to address participation by nonincumbents as a result of removal of the federal right of first refusal from Commission-jurisdictional tariffs and agreements. However, we note that nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. Public utility transmission providers must establish this framework in consultation with stakeholders and we encourage stakeholders to fully participate.

1. Need for Reform Concerning Nonincumbent Transmission Developers

a. Commission Proposal

228. As discussed above, Order No. 890 sought to reduce opportunities for undue discrimination and preference in the provision of transmission service. With regard to the transmission planning process, the Commission established nine transmission planning principles to prevent undue discrimination. However, Order No. 890 did not specifically address the potential for, or effect of, undue preference to incumbent utilities over nonincumbent transmission developers through practices applied within transmission planning processes. The Commission observed in the October 2009 Notice[200] that, as a result of existing practices in some areas, a nonincumbent transmission developer may lose the opportunity to construct its proposed transmission project to the incumbent transmission owner if that owner has a federal right of first refusal to construct any transmission facility in

[200] Federal Energy Regulatory Commission, Notice of Request for Comments; Transmission Planning Processes under Order No. 890; Docket No. AD09–8–000, October 8, 2009 (October 2009 Notice).

its service territory. The October 2009 Notice sought comment whether such a federal right of first refusal for incumbent transmission owners unreasonably impedes the development of merchant and independent transmission and, if so, how that impediment could be addressed.

229. Based on the comments received, the Commission determined that if a regional transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents that regional transmission planning process cannot meet the Order No. 890 transmission planning principle of being ''open.'' Moreover, the Commission stated that such regional planning process may not result in a cost-effective solution to regional transmission needs, and transmission projects in a regional transmission plan therefore may be developed at a higher cost than necessary.[201] As a result, regional transmission services may be provided at rates, terms and conditions that are not just and reasonable. In addition, the Commission determined in the Proposed Rule that there appeared to be opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. The Commission explained that, where an incumbent transmission owner has a federal right of first refusal, a nonincumbent transmission developer risks losing its investment to develop a transmission project that it proposed in the regional transmission planning process, even if the transmission project that the nonincumbent transmission developer proposed is in a regional transmission plan. The Commission noted that nonincumbent transmission developers may be less likely to participate in the regional transmission planning process under these circumstances.

230. To address these issues, the Commission proposed to reform provisions in public utility transmission providers' OATTs or other agreements subject to the Commission's jurisdiction that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities that are in a regional transmission plan.

b. Comments

231. A number of commenters support the Commission's proposal to address federal rights of first refusal in Commission-jurisdictional tariffs and agreements.[202] For example, Federal Trade Commission states that the existence of a federal right of first refusal in jurisdictional tariffs and agreements reduces capital investment opportunities for potential nonincumbent developers by increasing their risk, encourages free ridership among incumbent developers, and creates a barrier to entry. A number of state utility commissions and consumer advocates agree, arguing that such provisions impede transmission development and that removing the provisions would provide a level playing field for incumbent and nonincumbent transmission developers.[203]

232. For example, California Department of Water Resources states that competition among transmission providers that promotes efficiencies and innovation should be supported in regulatory policy and transmission planning. New Jersey Board, Connecticut & Rhode Island Commissions and Massachusetts Departments support the proposal to remove a federal right of first refusal, also stating that competition among project sponsors will result in lower cost approaches to meeting system needs. They caution, however, that equal rights must be followed by equal responsibilities and obligations at the federal, regional, state and local level. New England States Committee on Electricity contends that increased competition about which entity will build transmission facilities could help improve cost controls over time. Pennsylvania PUC supports the proposal to eliminate undue discrimination against nonincumbent transmission developers and the attempt to eliminate some of the barriers to full participation by nonincumbent transmission developers. Pennsylvania PUC cautions the Commission, however, to continue to respect Pennsylvania PUC's statutory responsibility to review and approve the siting of transmission projects located in Pennsylvania. Ohio Commission agrees that eliminating rights of first refusal has merit to the extent that parameters are established to ensure that ratepayers see cost savings and enhanced reliability. Ohio Consumers' Counsel and West Virginia Consumer Advocate Counsel state that eliminating barriers to participation can encourage additional transmission development that could be constructed at lower cost to consumers. Arizona Corporation Commission supports the removal of rights of first refusal, but states that it does not see this as having an impact on an incumbent utility's obligations to serve or affecting the transmission planning process currently utilized in Arizona.

233. Some commenters representing transmission-dependent and municipal utilities express support for the Commission's proposal.[204] Transmission Dependent Utility Systems state that a right of first refusal can prevent or delay construction of needed transmission facilities proposed by nonincumbent transmission developers and also can be used to block transmission access for generation resources that are not associated with the incumbent transmission provider. Northern California Power Agency states that any entity, whether an investor-owned utility, municipal entity, or independent developer, should have the right to propose, construct, and own transmission projects, subject to minimum safety and reliability requirements. Eastern Massachusetts Consumer-Owned System states that eliminating the right of first refusal should help open the door to municipal utility participation in transmission ownership on a larger scale.

234. Others supporting the proposal include entities representing independent developers of transmission and generation.[205] NextEra states that allowing the right of first refusal to continue would impede development of innovative transmission solutions in that a transmission project is unlikely to advance very far if its developer cannot

[201] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 87–88.

[202] *E.g.,* Federal Trade Commission; American Antitrust Institute; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; American Forest & Paper; DC Energy; Elmer John Tompkins; EIF Management; 26 Public Interest Organizations; and Boundless Energy; Pennsylvania PUC; Connecticut & Rhode Island Commissions; Northern California Power Agency; Eastern Massachusetts Consumer-Owned System; and Transmission Dependent Utility Systems; Arizona Corporation Commission; New Jersey Board; and California PUC; NextEra; AWEA; Anbaric and PowerBridge; Clean Line; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; FirstWind; Green Energy and 21st Century; Colorado Independent Energy Association; Enbridge; Primary Power; and Western Independent Transmission Group.

[203] *E.g.,* Arizona Corporation Commission; Connecticut & Rhode Island Commissions; New England States Committee on Electricity; New Jersey Board; Massachusetts Departments; Ohio Consumer's Counsel; Pennsylvania PUC; and West Virginia Consumer Advocate.

[204] *E.g.,* Eastern Massachusetts Consumer-Owned System; Northern California Power Agency; Transmission Agency of Northern California; and Transmission Dependent Utility Systems.

[205] *E.g.,* NextEra; AWEA; Anbaric and PowerBridge; Clean Line; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; FirstWind; Green Energy and 21st Century; Colorado Independent Energy Association; Enbridge; Primary Power; and Western Independent Transmission Group.

be confident that it can see the transmission project to its completion. Clean Line supports the elimination of the right of first refusal and states that encouraging the participation of nonincumbent transmission developers in the regional transmission planning process would increase competition and expand development, which can ultimately lead to lower costs for ratepayers. LS Power states that a right of first refusal and all other discriminatory rules should be eliminated from transmission planning processes inside and outside of RTOs and ISOs.[206] Pattern Transmission states that rights of first refusal and similar preferences favoring incumbent transmission owners do not result in transmission rates that are just and reasonable, are inherently preferential and unduly discriminatory, and suggests that the right of first refusal allows incumbent transmission owners to engage in gaming. Primary Power contends that removing a right of first refusal from all Commission-jurisdictional tariffs and agreements would provide an opportunity for a wider variety of technical and financial resources to participate in transmission infrastructure development. Western Independent Transmission Group contends that the ability of incumbent transmission owners to construct transmission projects proposed by other transmission developers under a right of first refusal is equivalent to the seizure of intellectual property.

235. Some commenters cite to examples that they believe show the benefits of removing barriers to competition by nonincumbent transmission developers. For example, Western Independent Transmission Group points to the success of Texas's Competitive Renewable Energy Zone planning process in supporting transmission development by nonincumbent developers. Also, Western Independent Transmission Group points to the Trans Bay Cable, Neptune, and Cross Sound Cable transmission projects, which were developed by nonincumbent transmission developers. Pattern Transmission cites the benefits associated with increased competition in the telecommunications and railroad industries, arguing that comparable benefits are available in the electric industry.

236. Some commenters supporting the Commission proposal argue that the record in this proceeding is sufficient to support taking action at this time. Primary Power states that Commission is ''not required to make specific findings so long as the agency's factual determinations are reasonable.'' [207] LS Power states that the Commission has legal authority to address discrimination against prospective transmission owners, it has a substantial record that rights of first refusal are unreasonable and result in undue discrimination, thus satisfying the *National Fuel* standard.

237. Commenters supporting the Proposed Rule generally contend that the elimination of rights of first refusal in Commission-jurisdictional tariffs and agreements would not be in conflict with the responsibilities of incumbent transmission providers, such as the obligation imposed under RTO and ISO membership agreements to build transmission facilities identified as needed in regional transmission plans.[208] These commenters state that, to the extent that an incumbent transmission owner feels unreasonably burdened by its obligations to build, a nonincumbent transmission developer would welcome the opportunity to respond to competitive solicitations to build the obligatory transmission projects. Such commenters further note that, as independent transmission developers build transmission projects and become transmission owners themselves, they also may be subject to appropriate obligations to build adjacent or connecting transmission facilities. Northwest & Intermountain Power Producers Coalition states that an incumbent's service obligation would come into play only if no alternative proposal is available to meet the identified need and that, where better alternatives are identified in the planning process, there is no good reason to prevent the better alternative from being constructed merely because the incumbent has an obligation to construct where a better alternative does not exist. Western Independent Transmission Group suggests that the obligation to build is a benefit, not a burden, because an incumbent transmission developer that constructs a transmission project pursuant to an obligation will receive full cost-of-service recovery, including a fair rate of return on its investment.

238. Others urge the Commission to provide thoughtful consideration to the potential impacts of its proposal.[209] Energy Future Coalition states that, while a right of first refusal should not give incumbent utilities the ability to block or stall construction of needed infrastructure within their service territories, or to inflate the costs of such projects, transmission goals will be frustrated if elimination of such provisions bogs down the transmission planning process. New England Transmission Owners state that, before taking action to eliminate any right of first refusal, the Commission should consider the unique way in which transmission projects are identified for development, the success of the current planning process, and the unique characteristics of the New England system that make the current process appropriate for this region. National Rural Electric Coops suggest that, prior to proceeding with the proposed reforms, the Commission consider adoption of principles to allow load-serving entities to participate in projects developed by traditional and independent transmission providers and to have the right to acquire an ownership participation in any project that it built within their service territories.

239. A number of commenters oppose any alteration of rights of first refusal in Commission-jurisdictional tariffs and agreements, arguing that there is insufficient evidence to justify removal of the right of first refusal.[210] Edison Electric Institute states that, on the contrary, there has been substantial evidence submitted to the Commission that a right of first refusal benefits consumers and results in lower rates, evidence that the Commission has not sought to rebut. Southern California Edison alleges that the Commission provides nothing more than speculative and vague statements that a right of first refusal may preclude nonincumbent transmission developers from participating in the regional transmission planning process and, in turn, affect rates for transmission service. ITC Companies contend that a right of first refusal is not the primary barrier to new market entrants and that they see no impediment to

[206] LS Power citing *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010) (*reh'g pending*); *Central Transmission, LLC* v. *PJM Interconnection L.L.C.*, 131 FERC ¶ 61,243 (2010).

[207] Primary Power cites to *Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667, 688 (DC Cir. 2000).

[208] *E.g.*, Anbaric and PowerBridge; Green Energy and 21st Century; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; Primary Power; Transmission Agency of Northern California; and Western Independent Transmission Group.

[209] *E.g.*, Energy Future Coalition; New England Transmission Owners; and MidAmerican.

[210] *E.g.*, California ISO; SPP; CapX2020 Utilities; Edison Electric Institute; Southern California Edison; Indianapolis Power & Light; ITC Companies; MidAmerican; Oklahoma Gas & Electric; PSEG Companies Comments; and San Diego Gas & Electric.

nonincumbent transmission developers pursuing development opportunities through a partnership model whereby right of first refusal rights are delegated. Oklahoma Gas & Electric notes that a number of transmission-only companies have announced significant transmission projects in SPP and, joined by MISO Transmission Owners, argues that it is premature for the Commission to determine that further reforms are needed to further encourage development.

240. Citing *National Fuel*,[211] some commenters argue that the Commission points to no evidence of actual discrimination or adverse impact on rates and that it must identify something more than theoretical possibilities to justify elimination of federal rights of first refusal.[212] Indicated PJM Transmission Owners assert that, if the Commission intends to rely solely on the effects of potential discrimination, in the absence of evidence of abuse, it must explain why the historical right of incumbent transmission owners to construct additions in their service territories so endangers open access to transmission service at just and reasonable rates as to justify a complete rearrangement of the relationship between public utilities, state regulators, and ultimate customers. MISO Transmission Owners state that the Proposed Rule fails to demonstrate why the existing complaint procedures under section 206 do not protect third parties from such theoretical harm.

241. Many of these commenters argue that preserving a federal right of incumbent transmission owners to build within their service territories is the best method to achieve the Commission's overall transmission goals. Such commenters contend that incumbent transmission owners are better situated to build new transmission facilities.[213] For example, Oklahoma Gas & Electric argues that incumbent transmission owners are often in the best position to determine where new transmission is needed on their system. CapX2020 Utilities and MidAmerican state that load serving transmission providers have a long history and relationship with state regulatory bodies that brings value to getting needed transmission developed. Ad Hoc Coalition of Southeastern Utilities and Southern Companies contend that incumbent transmission owners are better situated to obtain any necessary approval from state regulators to recover the cost of transmission facilities through bundled retail tariffs and that nonincumbent developers may have no obligation or ability to do so, depriving the state of an opportunity to determine that the proposal is the most reliable and cost-effective alternative. Ad Hoc Coalition of Southern Utilities adds that a nonincumbent developer's lack of a funding mechanism based on retail rates is a function of the state-based ratemaking process, not a preference for incumbent transmission owners.

242. Other commenters question the potential impact removal of a federal right of first refusal may have on transmission rates.[214] North Dakota & South Dakota Commissions argue that there is no evidence to suggest that nonincumbents are better situated to provide lower cost or more reliable service, and note that nonincumbents are not regulated by state commissions and not subject to state law obligations regarding reliability or state law oversight of their operations. Alabama PSC states concern that the proposed elimination of the incumbent's federal right of first refusal could increase costs to Alabama consumers. Edison Electric Institute argues that the Commission's proposal ignores longstanding policy that a public utility's investment is assumed to be prudent when a range of options are available, arguing that the Proposed Rule would have a reasonable rate depend upon the identity of the builder of the transmission facility.

243. Some commenters argue that any lower costs that result from competition to own and construct transmission projects is likely to be more than offset by inefficiencies created in the transmission planning process and a loss of economies of scale and scope.[215] Pacific Gas & Electric states that competition may have cost impacts to incumbent transmission owners relating to their obligation to maintain or improve reliability and security of the existing transmission system to comply with current and future reliability standards. Southern Companies contend that consumers bear the risk of nonincumbent developers declaring bankruptcy or becoming unable or unwilling to complete a transmission project, suggesting that the Commission require ''step in'' rights in such circumstances to facilitate an incumbent transmission owner's assumption of the project, should it voluntarily choose to do so. Transmission Dependent Utility Systems state that the proposal could raise costs by causing customers outside of an RTO/ISO region to pay both the full costs of the incumbent transmission provider's transmission system and the full incremental costs of any nonincumbent transmission projects necessary to serve its load.

244. Indicated PJM Transmission Owners assert that, even if a nonincumbent were to propose a less expensive transmission project for recovery through cost-based rates, there is no assurance that its final costs will be equal to or lesser than its estimate, or that it has a greater likelihood of staying within its cost estimate than an incumbent transmission owner. They contend that the Commission misapplies cost-effectiveness principles to non-rate matters beyond its authority, without factual or logical support. PPL Companies agree, arguing that consumers will bear the risk of cost overruns by nonincumbent transmission developers. California ISO notes that the Trans Bay Cable, cited by Western Independent Transmission Group, had significant cost overruns, and that the Neptune and Cross Sound Cable transmission projects were merchant transmission projects that, as direct current transmission lines, involved fewer concerns about system compartmentalization and fragmentation. Southern California Edison states that under the Proposed Rule, there does not appear to be any incentive for project participants to develop cost-efficient proposals because it is not clear if and how customer costs would be considered in project selection.

245. Several comments suggest that the proposal is based on a false assumption that providing for greater competition in the provision of transmission development will produce benefits to consumers.[216] They state that unlike generation, a competitive model cannot be adopted for wholesale transmission because customers have no meaningful alternative transmission provider and the development cycle for transmission is much longer than for

[211] *National Fuel*, 468 F.3d 831.

[212] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Edison Electric Institute; Indicated PJM Transmission Owners; Large Public Power Council; MidAmerican; MISO Transmission Owners; Oklahoma Gas & Electric; PSEG Companies; Salt River Project; and San Diego Gas & Electric. Large Public Power Council also cites to *Associated Gas Distributors.*

[213] *E.g.*, PJM; CapX2020 Utilities; Edison Electric Institute; Georgia Transmission Corporation; MidAmerican; Omaha Public Power District; Pacific Gas & Electric; Sunflower and Mid-Kansas; and Transmission Access Policy Study Group.

[214] *E.g.*, Alabama PSC; City of Santa Clara; Dominion; Edison Electric Institute; MidAmerican; Oklahoma Gas & Electric; PSEG Companies; Southern California Edison; Sunflower and Mid-Kansas; and Xcel.

[215] *E.g.*, Dominion; PSEG Companies; North Dakota & South Dakota Commissions; and Oklahoma Gas & Electric Company.

[216] *E.g.*, California ISO; Indianapolis Power & Light; Oklahoma Gas & Electric Company; and Pacific Gas & Electric.

generation. California ISO disagrees that the benefits of competition cited by Western Independent Transmission Group and Pattern Transmission are relevant to its transmission planning process. PPL Companies similarly argues that commenters arguing that eliminating the right of first refusal benefits competition misunderstand the nature of the transmission planning process, noting that RTO planning processes do not involve price competition or consumer choice. PPL Companies contend that eliminating the right of first refusal would not add choice for consumers since the transmission projects included in RTO plans are driven by needs, and not by proposals from incumbent or nonincumbent developers.

246. A number of commenters assert that removing a federal right of first refusal would complicate and undermine the transmission planning process.[217] Delaware PSC states that the Proposed Rule would fundamentally change the way transmission facilities are proposed, selected, and built, and requires thoughtful consideration of all its implications. MISO states that placing regional planners in a role of deciding who should build introduces a level of financial competition to the planning process that is fundamentally at odds with the high level of openness and collaboration under the current approach. Kansas City Power & Light and KCP&L Greater Missouri contend that the proposal would exacerbate an already complex and arduous process to study, plan and implement regional transmission infrastructure. Dominion states that eliminating a federal right of first refusal would create a model where competitively sensitive information will be withheld from open discussion, thus making the planning process less collaborative. Xcel agrees that the proposal could harm the planning process and that disagreements about transmission project selection could have negative impacts on state-level siting and routing approval processes.

247. Some commenters caution that implementation of the proposed reforms could have unintended consequences affecting reliability.[218] These commenters generally contend that eliminating federal rights of first refusal could cause, or exacerbate, operational and reliability challenges for transmission system operations and could produce operational issues as each transmission provider will have to coordinate with more entities to address specific reliability issues. Many of these commenters contend that increasing the number of entities involved in transmission ownership and grid operations would make coordination, maintenance, and service restoration more difficult by further fragmenting the transmission system, which they note has been a concern of the Commission in the past.

248. Several commenters contend that the right of first refusal is inextricably linked to the obligation to build imposed under RTO and ISO membership agreements, justifying any difference in treatment between incumbent transmission owners and nonincumbent transmission developers.[219] These commenters generally argue that retention of an obligation to build without a corresponding right of first refusal would impose a serious and unjust and unreasonable burden on incumbent transmission owners and is in violation of the FPA. Some state commissions express concern that the Commission's proposal may undermine the ability of utilities to meet their load service obligations.[220] Other commenters state that it is important to maintain an obligation to build for its transmission owning members to ensure transmission projects needed for reliability can be developed promptly.[221] Some commenters contend that the Commission's proposed reforms would result in undue discrimination against incumbent utilities, giving nonincumbent transmission developers the opportunity to propose and build a transmission facility, whereas incumbents would be required to build any needed transmission facility, including those that may be abandoned or not completed by the nonincumbent developer.[222] Many of these commenters contend this would permit nonincumbent transmission developers to ''cherry pick'' only the most advantageous projects in terms of financial reward and development risk.[223] Southern California Edison contends that the Commission's proposal amounts to establishing a free call on a utility's capital without any return to compensate it for the time period in which that capital had to be held in reserve to meet a backstop obligation to build.

249. Several commenters express concern about the impact that removing a federal right of first refusal in Commission-jurisdictional tariffs and agreements may have on RTO and ISO participation.[224] For example, MISO states that the right of its transmission owner members to build transmission facilities identified through the planning process was, and remains, one of the key considerations for its transmission owners to have formed, and to remain a part of, the voluntary RTO. MISO Transmission Owners argue that the Proposed Rule would result in undue discrimination between transmission owners voluntarily participating in RTOs and transmission owners that have not joined an RTO. MISO Transmission Owners state that, without a right to construct new transmission facilities within their own systems, a transmission owner could experience substantial erosion of its revenues over time as a result of RTO participation. MISO Transmission Owners add that construction obligations and rights in RTOs and ISOs have been carefully designed to ensure that RTOs, ISOs, and their members can comply with all applicable state and federal service obligations and reliability standards. Southern Companies state that the Commission should clarify that the reforms relating to nonincumbent transmission developers do not apply in non-RTO regions. On the other hand, Transmission Agency of Northern California emphasizes that the Commission's proposal to remove a right of first refusal from all Commission-approved tariffs and agreements should apply in both non-RTO/ISO and RTO/ISO regions.

[217] *E.g.*, AEP; Allegheny Energy Companies; Baltimore Gas & Electric; Dominion; Edison Electric Institute; First Energy Service Company; Indianapolis Power & Light; Kansas City Power & Light and KCP&L Greater Missouri; MidAmerican; MISO; MISO Transmission Owners; Pacific Gas & Electric; and Southern California Edison.

[218] *E.g.*, Baltimore Gas & Electric; California ISO; Edison Electric Institute; MidAmerican; Oklahoma Gas & Electric; Pacific Gas & Electric; PJM; PSEG Companies; Southern California Edison; and Xcel.

[219] *E.g.*, ISO New England; PJM; SPP; Federal Trade Commission; SPP; MISO Transmission Owners; Edison Electric Institute; Georgia Transmission Corporation; Indianapolis Power & Light; Large Public Power Council; Nebraska Public Power District; Arizona Public Service Company; Oklahoma Gas & Electric; MidAmerican; PSEG Companies; San Diego Gas & Electric; Southern California Edison; Tucson Electric; Xcel; Allegheny Energy Companies; Duke; Baltimore Gas & Electric; Dominion; E.ON; Exelon; Westar Integrys; and FirstEnergy Service Company.

[220] *E.g.*, Florida PSC; Minnesota PUC; and Minnesota Office of Energy Security.

[221] *E.g.*, ISO New England; MidAmerican; and MISO Transmission Owners.

[222] *E.g.*, Baltimore Gas & Electric; Edison Electric Institute; FirstEnergy Service Company; Large Public Power Council; MidAmerican; MISO Transmission Owners; PPL Companies; PSEG Companies; and Xcel.

[223] *E.g.*, Baltimore Gas & Electric; California ISO; CapX2020 Utilities; Indianapolis Power & Light; Oklahoma Gas & Electric; Southern California Edison; and Xcel.

[224] *E.g.*, MISO; MISO Transmission Owners; Edison Electric Institute; Alliant Energy; MidAmerican; and Indianapolis Power & Light.

250. Some commenters argue that the existence of native load and state franchise obligations further distinguish incumbent transmission owners from nonincumbent transmission developers, justifying retention of federal rights of first refusal.[225] These commenters assert that nonincumbent developers are not similarly situated because they can select the transmission projects they wish to pursue and ignore those they deem too risky or insufficiently profitable, unencumbered by a ''duty to serve'' requiring the construction and maintenance of facilities necessary to render reliable, cost-effective service to customers in their service territories. For example, Baltimore Gas & Electric states that it and others view their licensed obligations to protect their service territory from power outages as being paramount over their mere financial interests. Edison Electric Institute and MISO Transmission Owners argue that differing state law obligations have been found to be legitimate factors in determining that two entities are not similarly situated.[226] San Diego Gas & Electric contends that removal of federal rights of first refusal raises constitutional concerns since, as regulated entities, public utility transmission providers are entitled under well-established law to receive a reasonable rate of return on their investment in transmission infrastructure in discharging their state-mandated service obligations.[227]

251. A number of commenters suggest that the Commission consider partial elimination of federal rights of refusal.[228] Many of these commenters endorse SPP's current mechanism, under which an incumbent utility has a 90-day time limit to exercise its right to construct a facility included in the regional transmission plan. AEP suggests that the Commission consider a phased approach, beginning with a time limit on the exercise of any right of first refusal and, if this does not substantially address the Commission's concerns, then consider further modification or elimination of the right of first refusal. AEP suggests that the Commission also could require each region to report back to the Commission within two years on its experience implementing the time-limited right of first refusal as a basis for the Commission to consider whether a fundamental change of the existing regional transmission planning process is needed. California PUC and Exelon argue that incumbent transmission owners should maintain the right of first refusal for reliability projects located within a single zone. Transmission Access Policy Study Group recommends that the Commission retain a limited right of first refusal that can be exercised only when the incumbent transmission provider forgoes transmission incentives for the project and offers meaningful joint ownership opportunities on reasonable terms. Other commenters disagree with proposals to maintain limited rights of first refusal, generally arguing that such proposals would perpetuate the entry barrier.[229]

252. Finally, some commenters suggest that the Commission engage in additional outreach on this issue before altering federal rights of first refusal.[230] They encourage the Commission to host a technical conference or initiate other proceedings so that all of these issues can be examined and potential solutions developed in a collaborative manner. Sunflower and Mid-Kansas contend that, if problems relating to a right of first refusal exist in a particular region, the issue should be addressed locally rather than imposing a one-size-fits-all solution across all regions.

c. Commission Determination

253. The Commission concludes that there is a need to act at this time to remove provisions from Commission-jurisdictional tariffs and agreements that grant incumbent transmission providers a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation.[231] Failure to do so would leave in place practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers. The Commission addresses the need for eliminating such practices in this section and, in the sections that follow, our legal authority to do so and the procedures by which public utility transmission providers must implement the removal of federal rights of first refusal from Commission-jurisdictional tariffs and agreements.

254. As the Commission recognized in Order Nos. 888 and 890, it is not in the economic self-interest of public utility transmission providers to expand the grid to permit access to competing sources of supply.[232] In Order No. 890, the Commission required greater coordination in transmission planning on a regional level to remedy the potential for undue discrimination by transmission providers that have an incentive to avoid upgrading transmission capacity with interconnected neighbors where doing so would allow competing suppliers to serve the customers of the public utility transmission provider.[233] Although basing its actions on its authority to remedy undue discrimination, the Commission found that ''[t]he coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis.'' [234]

255. In response to Order No. 890, regions across the country have implemented transmission planning processes that allow for consideration of alternative transmission projects proposed at the regional level to determine if they better meet the

[225] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Edison Electric Institute; Large Public Power Council; MISO Transmission Owners; Nebraska Public Power District; Xcel; PPL Companies; and Xcel. In support, Ad Hoc Coalition of Southeastern Utilities cites to *California Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 369 (2007); *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282, at P 36 (2006); and *Sebring Utils. Comm'n* v. *FERC*, 591 F.2d 1003, 1009 n.24 (5th Cir. 1979). MISO Transmission Owners also cite to *S. Cal. Edison Co.*, 59 FPC 2167, 2185–86 (1977).

[226] Edison Electric Institute and MISO Transmission Owners cite to *Town of Norwood* v. *FERC*, 202 F.3d 392, 403 (1st Cir. 2000).

[227] San Diego Gas & Electric supports these assertions by citing *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works* v. *Public Serv. Comm'n*, 262 U.S. 679 (1923).

[228] *E.g.*, California PUC; Transmission Dependent Utility Systems; SPP; AEP; Iberdrola Renewables; Indianapolis Power & Light; ITC Companies; MidAmerican; Oklahoma Gas & Electric; Southern California Edison; Westar; Xcel; CapX2020 Utilities; and SPP.

[229] *E.g.*, American Antitrust Institute; Anbaric and PowerBridge; LS Power; NextEra; Pattern Transmission; and Western Independent Transmission Group.

[230] *E.g.*, Delaware PSC; NextEra; San Diego Gas & Electric; and Tucson Electric.

[231] As explained in more detail in section III.B.3 below, the Commission purposely refers to ''federal rights of first refusal'' in this Final Rule because the Commission's action on this issue in this Final Rule addresses only rights of first refusal that are created by provisions in Commission-jurisdictional tariffs or agreements. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. This Final Rule does not require removal of references to such state or local laws or regulations from Commission-approved tariffs or agreements.

[232] Order No. 888, FERC Stats. & Regs. at 31,682; Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[233] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[234] *Id.*

region's needs.[235] The evaluation of alternative transmission solutions at the regional level is often referred to as ''top down'' planning.[236] In some regions, heavy emphasis is placed on ''top down'' regional planning for all or certain classes of transmission facilities. In other regions, local transmission plans are developed in which individual public utility transmission providers within the region identify solutions to their own local needs prior to the ''top down'' consideration of regional alternatives. This is often referred to as ''bottom up, top down'' planning.[237] Although the relative weight placed on ''bottom up'' or ''top down'' processes varies by region, all of these existing processes allow at some point for transmission project developers to offer alternative solutions for evaluation on a comparable basis pursuant to criteria that is set forth in the public utility transmission providers' OATTs.[238] By requiring the comparable evaluation of all potential transmission solutions, the Commission has sought to ensure that the more efficient or cost-effective solutions are in the regional transmission plan.[239]

256. The Commission is concerned that the existence of federal rights of first refusal may be leading to rates for jurisdictional transmission service that are unjust and unreasonable. Allowing federal rights of first refusal to remain in Commission-jurisdictional tariffs and agreements would undermine the consideration of potential transmission solutions proposed at the regional level. Just as it is not in the economic self-interest of public utility transmission providers to expand transmission capacity to allow access to competing suppliers, it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs. We conclude that an incumbent transmission provider's ability to use a right of first refusal to act in its own economic self-interest may discourage new entrants from proposing new transmission projects in the regional transmission planning process.

257. Federal rights of first refusal exacerbate these problems by, as the Federal Trade Commission and other commenters explain, creating a barrier to entry that discourages nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level. Many commenters note that significant investment is needed to support the development of a successful transmission project, yet there is a disincentive for a nonincumbent transmission developer to commit its resources to a potential transmission project when it runs the risk of an incumbent transmission provider exercising its federal right of first refusal once the benefits of the transmission project are demonstrated. The Commission recognizes that removing federal rights of first refusal in Commission-jurisdictional tariffs and agreements will not eliminate all obstacles to transmission development that may exist under state or local laws or regulations and, therefore, may not address all challenges facing nonincumbent transmission development in those jurisdictions. It does not follow, however, that the Commission should leave in place federal rights of first refusal. Moreover, the number of state commission commenters supporting the Commission's proposal indicate that, at a minimum, there is interest in those jurisdictions to explore the benefits of nonincumbent transmission development.

258. The Commission shares the concerns of some commenters that elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements, if not implemented properly, could adversely impact the collaborative nature of current regional transmission planning processes. The Commission addresses these concerns in section III.B.3 by modifying and clarifying the proposed framework for implementing our reforms, including elimination of the proposed requirement to allow a transmission developer to maintain for a defined period a right to build and own a transmission facility. In addition, this Final Rule does not require removal of a federal right of first refusal for a local transmission facility, as that term is defined herein.[240] The Commission disagrees with commenters asserting that reforming federal rights of first refusal would fundamentally alter regional transmission planning processes. Public utility transmission providers already are required to evaluate whether alternative transmission solutions proposed by other developers better meet the needs of the region. Therefore, existing regional transmission planning processes have mechanisms in place to weigh various alternatives against one another. Indeed, this is the fundamental nature of ''bottom-up, top-down'' transmission planning, in which local needs and solutions are combined within a region and analyzed to determine whether regional solutions would be more efficient or cost-effective than the local solutions identified by individual public utility transmission providers.[241]

259. The Commission understands that the degree to which existing transmission planning processes will be impacted by the elimination of federal rights of first refusal will vary by region, just as the current mechanisms used to evaluate competing transmission projects vary by region. For example, the public utility transmission providers in a region may, but are not required to, use competitive solicitation to solicit projects or project developers to meet regional needs. To the extent a region already has in place processes to rely on market proposals or competitive solicitations when identifying solutions to the region's needs, such existing processes may require relatively modest modifications to provide nonincumbent transmission providers with the opportunity to propose and construct transmission projects, consistent with state and local laws and regulations. In regions relying more heavily on local planning with less robust mechanisms to identify alternative transmission solutions at the regional level, more effort may be needed to implement the Commission's reforms. Within the implementation framework adopted below, the Commission provides each region with the flexibility necessary to identify the modifications to existing transmission planning processes that may be required as a result of removing

[235] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494; Order No. 890–A, FERC Stats. & Regs. ¶ 61,297 at P 215–16. Sponsors of generation and demand response solutions are provided comparable opportunities to offer their proposals in the regional transmission planning process. *Id.*

[236] *See, e.g.,* Pacific Gas & Electric Initial Comments describing top down planning.

[237] *See, e.g.,* Large Public Power Council Initial Comments describing bottom up planning.

[238] *See, e.g.,* Entergy OATT, Attachment K at § 3.12; Florida Power and Light OATT, Appendix 1 to Attachment K, §§ H and I; ISO New England OATT, Attachment K at § 4.2; Puget Sound Energy OATT, Attachment K at § 2; SPP OATT, Attachment O at § III.8.

[239] *See, e.g., Northwestern Corp.,* 128 FERC ¶ 61,040, at P 38 (2009); *El Paso Electric Co.,* 128 FERC ¶ 61,063, at P 15 (2009); *New York Independent System Operator, Inc.,* 129 FERC ¶ 61,044, at P 35 (2009).

[240] *See* definition *supra* section II.D of this Final Rule.

[241] Similarly, the Commission believes that concerns regarding the cost-effectiveness of nonincumbent transmission development are misplaced. For one solution to be chosen over another in the transmission planning process, there must be an evaluation of the relative economics and effectiveness of performance for each alternative. *See, e.g., New York Independent System Operator, Inc.,* 129 FERC ¶ 61,044 at P 35, n.26.

federal rights of first refusal from Commission-jurisdictional tariffs and agreements.

260. The Commission is not persuaded to abandon our proposed reforms to federal rights of first refusal based on arguments that incumbent transmission providers are better situated to build and operate transmission facilities. While we acknowledge that incumbent transmission providers may have unique knowledge of their own transmission systems, familiarity with the communities they serve, economies of scale, experience in building and maintaining transmission facilities, and access to funds needed to maintain reliability, we do not believe removing the federal right of first refusal diminishes the importance of these factors. An incumbent public utility transmission provider is free to highlight its strengths to support transmission project(s) in the regional transmission plan, or in bids to undertake transmission projects in regions that choose to use solicitation processes. However, we do not believe that, just because an incumbent public utility transmission provider may have certain strengths, a nonincumbent transmission developer should be categorically excluded from presenting its own strengths in support of its proposals or bids.

261. Various commenters argue that federal rights of first refusal are inextricably tied to obligations to build placed on incumbent transmission providers, such as those under RTO and ISO member agreements. We acknowledge that a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO or ISO, but we do not believe that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region. There are many benefits and obligations associated with membership in an RTO or ISO and an obligation to build at the direction of the RTO or ISO is only one aspect of the agreement. While implementation of reforms to federal rights of first refusal may change the package of benefits and burdens currently in place for transmission owning members of RTOs and ISOs, we find that such changes are necessary to correct practices that may be leading to rates for jurisdictional transmission service that are unjust and unreasonable.

262. Some commenters also contend that the federal right of first refusal is necessary for incumbent transmission providers to develop transmission facilities needed to comply with a reliability standard or an obligation to serve customers. We clarify that our actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint. The Final Rule continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation. Alternatively, an incumbent transmission provider may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation. Our decision today does not prevent an incumbent transmission provider from continuing to propose transmission projects for consideration in the regional transmission planning process and to receive regional cost allocation if those projects are selected in a regional transmission plan for such purposes, even if they are located entirely within its retail distribution service territory or footprint.

263. Given that incumbent transmission providers may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation to comply with their reliability and service obligations, delays in the development of such transmission facilities could adversely affect the ability of the incumbent transmission provider to meet its reliability needs or service obligations. To avoid this result, in section III.B.3 below, we require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations.

264. One function of the regional transmission planning process is to identify those transmission facilities that are needed to meet identified needs on a timely basis and, in turn, enable public utility transmission providers to meet their service obligations. Given the familiarity incumbent transmission providers have with their own systems, we expect that they will continue to participate actively in the regional transmission planning process to share their unique perspectives regarding whether various potential solutions meet particular needs of their systems. To the extent an incumbent transmission provider has concerns that a regional transmission alternative does not address the identified reliability needs or service obligations that would allow it to serve its customers reliably to meet state or local laws, whether upon initial evaluation or, as relevant, subsequent reevaluation, it can make such concerns known so that all relevant information regarding a regional transmission alternative can be considered.

265. The Commission disagrees that elimination of federal rights of first refusal would result in discrimination against incumbent transmission providers in favor of nonincumbent transmission developers. Once a member of an RTO or ISO, a nonincumbent transmission developer will be subject to the relevant obligations that apply to the RTO or ISO members. While it is true that the obligation of nonincumbent transmission developers to expand their transmission facilities, once within an RTO or ISO, may apply to fewer transmission facilities than those of an incumbent with a large footprint, and that some incumbent transmission providers may be subject to different requirements under state and local laws, it does not follow that eliminating federal rights of first refusal amounts to discrimination in favor of nonincumbent transmission developers. Rather, we are merely removing a barrier to participation by all potential transmission providers. With regard to concerns that our reforms will discourage entities from joining or maintaining membership in RTOs and ISOs, we note that a variety of factors must be weighed when evaluating the benefits and burdens of RTO/ISO membership. In addition, we reject Southern Companies' request that we clarify that the reforms related to nonincumbent transmission developers do not apply in non-RTO regions; the reforms apply equally to public utility

transmission providers in all regions. The Commission believes that the modifications and clarifications provided below with regard to the framework under which transmission developers will participate in the transmission planning process will alleviate some of the concerns expressed by commenters.

266. We are not persuaded by commenters who argue that the reliability of the transmission system is a function of the number of public utility transmission providers of that system. In fact, to enhance reliability, among other reasons, public utility transmission providers have historically connected to the transmission systems of others, as well as jointly owned transmission facilities, and have therefore developed experience, protocols, and business models for coordinated operations with multiple transmission providers, operators, and users. Moreover, many of the same commenters that raise reliability concerns also suggest that nonincumbent transmission developers instead pursue the merchant model of development, which similarly increases rather than decreases the number of transmission providers within a region. All providers of bulk-power system transmission facilities, including nonincumbent transmission developers, that successfully develop a transmission project, are required to be registered as functional entities and must comply with all applicable reliability standards.[242] Together with the additional requirements we adopt in section III.B.4 below, the Commission finds these protections sufficient to support our decision here to eliminate the federal rights of first refusal contained in Commission-jurisdictional tariffs and agreements.

267. The Commission recognizes that there may be circumstances when an incumbent transmission provider may be called upon to complete a transmission project that it did not sponsor. For example, a situation may arise where an incumbent transmission provider is called upon to complete a transmission project that another entity has abandoned. There also may be situations in which an incumbent transmission provider has an obligation to build a project that is selected in the regional transmission plan for purposes of cost allocation but has not been sponsored by another transmission developer. We clarify that both of these situations would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA. In addition, the Commission addresses reliability concerns that may arise under those circumstances below.

268. For the foregoing reasons, and in light of the evaluation procedures required in section III.B.3 below, the Commission finds that there is sufficient justification in the record to implement the requirements regarding rights of first refusal contained in Commission-jurisdictional tariffs or agreements. The Commission is not required to identify specific evidence to justify our actions today. Our task in this respect is to show that there is ‘‘ ‘ground for reasonable expectation that competition may have some beneficial impact.’ ’’[243] Although the Commission has previously accepted, in some cases, and rejected, in others, a federal right of first refusal, we find more persuasive in light of the comments in this proceeding, the Commission's reasoning in rejecting the federal right of first refusal. In particular, the Commission rejected a right of first refusal based on an expectation that ‘‘[t]he presence of multiple transmission developers would lower costs to customers.’’[244] We have carefully considered the record in the proceeding and therefore find further procedures to evaluate the need for the reforms adopted herein to be unnecessary.

269. Finally, we disagree with San Diego Gas & Electric that the elimination of a federal right of first refusal raises concerns under *FPC* v. *Hope Natural Gas Co.* and *Bluefield Water Works* v. *Public Serv. Comm'n.* As San Diego Gas & Electric notes, these cases stand for the principle that utilities are entitled to receive a reasonable return on their investment. They do not, however, speak to the issue of who may make an investment. They thus require only that a utility receive a reasonable rate of return on the investments that it makes, not that the utility receive a preferential right to make those investments.

2. Legal Authority To Remove a Federal Right of First Refusal

a. Commission Proposal

270. In the Proposed Rule, the Commission explained that the existing planning process may not result in a cost-effective solution to regional transmission needs and transmission projects that are in a regional transmission plan therefore may be developed at a higher cost than necessary. The Commission stated that the result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.[245] The Commission also stated that it may be unduly discriminatory or preferential to deny a nonincumbent public utility transmission developer that sponsors a project that is in a regional transmission plan the rights of an incumbent public utility transmission developer that are created by a public utility transmission provider's tariffs or agreements subject to the Commission's jurisdiction. Under these circumstances, the Commission noted that nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. The Commission stated that, if the regional transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents, it cannot meet the principle of being ''open.''

b. Comments Regarding the Commission's Authority To Implement the Proposal

271. Several commenters argue that the Commission has adequate statutory authority to undertake the reforms in the Proposed Rule.[246] Some of the commenters supporting the Commission's proposal to eliminate federal rights of first refusal from Commission-jurisdictional tariffs and agreements specifically addressed the scope of the Commission's authority under section 206 of the FPA. Primary Power contends that the Commission is authorized under section 206 to remove or limit the right of first refusal, which is a rule, practice, or contract condition subject to its jurisdiction. Primary Power states that, while the proposal to eliminate the right of first refusal represents a change in the Commission's policy of tolerance or occasional acceptance of the right of first refusal, this change in policy is justified as in the public interest. Primary Power

[242] 18 CFR 39.2(a) (2011).

[243] *Wisconsin Gas Company* v. *FERC,* 770 F.2d 1144, 1158 (DC Cir. 1985) (citing *FCC* v. *RCA Communications, Inc.,* 346 U.S. 86, 96 (1953)).

[244] *Cleco Power LLC,* 101 FERC ¶ 61,008 at P 117 (2002), *order terminating proceedings,* 112 FERC ¶ 61,069 (2005); *see also Carolina Power and Light Co.,* 94 FERC ¶ 61,273 at 62,010, *order on reh'g,* 95 FERC ¶ 61,282 at 61,995 (2001) (finding that a federal right of first refusal would unduly limit the planning authority and present the possibility of discrimination by self-interested transmission owners, potentially reduce reliability, and possibly precluding lower cost or superior transmission facilities or upgrades by third parties from being planned and constructed).

[245] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 87–88.

[246] *E.g.,* Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; Multiparty Commenters; and Primary Power.

argues that rights of first refusal are creatures of regulated services that are subject to federally-regulated tariffs and, therefore, proponents of rights of first refusal must find some independent legal basis for the property rights they seek to protect.

272. LS Power argues that the Commission has a duty to stamp out all forms of discrimination in the form of a right of first refusal, whether written in the OATT or other agreement, or simply as part of a long-standing bias arising from a closed planning process. LS Power contends that eliminating rights of first refusal is a critical step toward true competition in the electric industry, and essential to ensuring that new transmission infrastructure is provided to consumers at just and reasonable rates. LS Power notes that the Commission has historically required the elimination of provisions that are anticompetitive on their face.[247] Joined by American Forest & Paper, LS Power further argues that elimination of a federal right of first refusal would not be inconsistent with existing state laws, noting the support for the Commission proposal by a number of state commissions submitting comments.

273. Other commenters contend that the Commission does not have the legal authority to implement the proposed reforms related to rights of first refusal in Commission-jurisdictional tariffs or agreements. Some commenters argue that the FPA does not give the Commission the authority to address discrimination between incumbent and nonincumbent transmission developers, arguing that the FPA's protection against undue discrimination is concerned with the protection of consumer interests and does not extend to nonincumbent transmission developers.[248] Ad Hoc Coalition of Southeastern Utilities states that precedent shows that the rights of competitors are neither protected nor contemplated in FPA section 205(b)'s proscription against undue discrimination.[249] Edison Electric Institute agrees, arguing that an undue discrimination analysis in the context of the right of first refusal provisions and planning processes is unsupportable, explaining that such provisions are not rates, terms, and conditions of a service that a transmission owner provides to its customers. Edison Electric Institute states that the Commission previously has not taken the step of characterizing transmission planning as an obligation or service to non-customers to facilitate their competing efforts to own transmission facilities. Edison Electric Institute further states that the comparability analysis for undue discrimination could not apply because ownership is not a service that a transmission owner provides to itself.

274. Indicated PJM Transmission Owners contend that the undue discrimination concerns underlying Order. No. 888, regarding access to transmission facilities for loads and for competing suppliers of wholesale electricity, are not present here. Indicated PJM Transmission Owners argue the Commission does not and cannot find that relying on incumbent transmission owners to build necessary upgrades to their systems discriminates either in the terms of service available to different classes of transmission customers or in the terms upon which wholesale sellers and buyers gain access to the transmission system.

275. Some commenters analogize to the Commission's jurisdiction under section 205 of the FPA, arguing that there are only two types of undue discrimination actionable under section 205: treating similar customers differently or affording similar treatment to dissimilar customers.[250] Some of these commenters assert that the court in *City of Frankfort* v. *FERC*[251] noted that section 205 provisions focus on the fair treatment of customers. Similarly, Nebraska Public Power District states *Public Service Commission of Indiana*[252] stands for the proposition that the antidiscrimination policy in section 205(b) is violated where one consumer has its rates raised significantly above what other similarly situated consumers are paying.

276. Other commenters also argue that the Commission lacks general jurisdiction over the siting, construction, or ownership of transmission facilities, matters they assert Congress intentionally left to the states, as demonstrated by a comparison between the FPA and the Natural Gas Act.[253] Commenters assert that the proposal to adopt rules governing who can build transmission within an incumbent transmission owner's zone exceeds the authority conferred upon the Commission under the FPA to regulate the terms and conditions of service and, in essence, create a federal franchise for transmission service.[254]

277. Other commenters argue that the Commission is provided only limited backstop siting authority under section 216 of the FPA, a grant of authority that the courts have emphasized is subservient to the primary jurisdiction of the states.[255] Oklahoma Gas & Electric Company argues that, in enacting section 215 of the FPA, Congress expressly declined to grant the Commission the authority to require the construction of facilities or the expansion of the grid. PPL Companies contend that the Commission's jurisdiction under FPA sections 210 and 211 to order existing utilities to enlarge their facilities, if necessary to permit transmission service or interconnection, can be invoked only pursuant to specific procedures and after specific findings are made.

278. Oklahoma Gas & Electric Company asserts that, for the Commission to extend its jurisdiction over actions that indirectly affect activity otherwise governed by the states, the Commission must show that the action in question has a direct and significant effect on jurisdictional rates. Oklahoma Gas & Electric Company argues that the courts are unwilling to allow the Commission to regulate activity if, in so doing, the Commission is directly regulating activity that was specifically reserved for the states.[256]

[247] LS Power (citing *Gulf States Utils. Co.,* 5 FERC ¶ 61,066 (1978)).

[248] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; Nebraska Public Power District; Omaha Public Power District; Xcel; and Indicated PJM Transmission Owners (citing *Grand Council of the Crees* v. *FERC,* 198 F.3d 950, 956 (DC Cir. 2000)).

[249] Ad Hoc Coalition of Southeastern Utilities cites to *Brunswick Corp.* v. *Pueblo Bowl-O-Mat, Inc.,* 429 U.S. 477, 487–89 (1977), *Cargill, Inc.* v. *Montfort of Colorado, Inc.,* 479 U.S. 104, 115–17 (1976), *City of Frankfort* v. *FERC,* 678 F.2d 699, 707 (7th Cir. 1982).

[250] *E.g.,* Nebraska Public Power District; Large Public Power Council; and MISO Transmission Owners. Some of these commenters cite to *Alabama Elec. Coop., Inc.* v. *FERC,* 684 F.2d 20, 27–28 (DC Cir. 1984), *Sacramento Mun. Util. Dist.* v. *FERC,* 474 F.3d 797, 802 (DC Cir. 2007), *City of Vernon* v. *FERC,* 845 F.2d 1042, 1046 (DC Cir. 1988), *Ohio Power Co.* v. *FERC,* 744 F.2d 162, 165 n.3 (DC Cir. 1984), and *''Complex'' Consol. Edison Co.* v. *FERC,* 165 F.3d 992, 1012 (DC Cir. 1999).

[251] *City of Frankfort* v. *FERC,* 678 F.2d 699, 704 (7th Cir. 1982).

[252] *Pub. Serv. Comm'n of Indiana, Inc.* v. *FERC,* 575 F.2d 1204, 1213 (7th Cir. 1978).

[253] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Oklahoma Gas and Electric Company; Omaha Public Power District; PPL Companies; Large Public Power Council; Xcel; Indianapolis Power & Light; Edison Electric Institute; Indicated PJM Transmission Owners; and Virginia State Corporation Commission. Indicated PJM Transmission Owners cite to *Altamont Gas Transmission Co.* v. *FERC,* 92 F.3d 1239, 1248 (DC Cir. 1996).

[254] *E.g.,* PPL Companies and PSEG Companies.

[255] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Indicated PJM Transmission Owners; Oklahoma Gas & Electric Company; and PPL Companies. Indicated PJM Transmission Owners cite to *Piedmont Envtl. Council* v. *FERC,* 558 F.3d 304 (4th Cir. 2009).

[256] Oklahoma Gas & Electric Company (citing *Northwest Central Pipeline Corp.* v. *State Corp. Comm'n of Kansas,* 489 U.S. 493 (1989); *Connecticut Dept. of Pub. Util. Control* v. *FERC,* 569

Continued

Oklahoma Gas & Electric Company cites to *National Association of Regulatory Utility Commissioners* v. *FERC,* 475 F.3d 395, 401 (DC Cir. 2004), where the court found that Commission regulations related to generator interconnection procedures bore a close enough relationship to its authority over jurisdictional transmission services that the exercise of jurisdiction over interconnection service was permissible.

279. Commenters opposing the Commission's proposed reforms generally reject the notion that the Commission is acting only to eliminate the federal right of first refusal, stating that the Proposed Rule would go much farther by regulating the protocols for determining the entity responsible to construct an upgrade. Indicated PJM Transmission Owners argue that, to the extent a state-created right is reflected in an RTO or ISO tariff or agreement, it cannot then be converted by the Commission into a federal based right that the Commission can eliminate by its own regulation. Indicated PJM Transmission Owners assert that the fact that the transmission provider may be an RTO or ISO does not expand the Commission's jurisdiction because the transmission owner is still the public utility that makes and supports financial investments. They argue that the Commission cannot use such a voluntary association to require utilities to surrender their statutory rights, in accordance with *Atlantic City Electric Co.* v. *FERC.*[257]

280. Other commenters similarly agree that not every provision of a Commission-jurisdictional rate schedule or tariff governs the terms and conditions of jurisdictional services.[258] For example, PPL Companies argues that there are numerous provisions in agreements required to be filed with the Commission that are not rates or other terms or conditions that affect rates, such as provisions addressing force majeure and indemnification. PPL Companies and others point to provisions in transmission owner agreements or RTO operating agreements that establish governance as an example of terms that are beyond the Commission's jurisdiction.[259] Indicated PJM Transmission Owners argue that, consistent with *CAISO* v. *FERC,* section 206 is not implicated because the building and owning of an upgrade is not a practice or contract that affects a rate, charge, or classification for transmission. Indicated PJM Transmission Owners argue that regulation of the determination of which entity constructs transmission additions and expansions is a regulation of whether the utility can provide a service at all, not the rate for the service. Indicated PJM Transmission Owners explain that *CAISO* v. *FERC* noted that the FPA provides the Commission with limited power regarding corporate governance in section 305, which involves interlocking directorates, and this supports the proposition that section 206 was not intended to reach such matters.[260]

281. Indicated PJM Transmission Owners contend that each of the choices a utility's management makes potentially constitutes a ''practice'' that eventually affects rates insofar as the utility seeks to recover the resulting costs. If the Commission concludes that an investment or other business decision is the product of imprudent management, Indicated PJM Transmission Owners contend that the Commission has authority to consider denying recovery of excessive costs resulting from that decision, not to supplant the public utility's management's decision-making authority.[261] Joined by FirstEnergy Service Company, Indicated PJM Transmission Owners argue that a fundamental premise of the FPA is that a utility has a right to recover prudently incurred costs, and a corollary of this principle is that a utility must have the right to decide whether to make those investments.[262]

282. Indicated PJM Transmission Owners disagree with the Commission's statement that the regional transmission planning processes that do not consider and evaluate of projects proposed by nonincumbent transmission developers cannot meet the principle of being ''open.'' They argue that the Commission cannot, by relying upon nondiscrimination principles, bootstrap authority it does not have for mandating the sponsorship model. Citing *Office of Consumers' Counsel* v. *FERC,*[263] Indicated PJM Transmission Owners argue that the Commission cannot redefine the transmission planning principles adopted in Order No. 890 to encompass matters that were never contemplated when it was issued. Indicated PJM Transmission Owners assert that nothing about the transmission owners' construction rights and obligations prohibits parties from participating in the process or proposing transmission projects. They state that the Commission has offered no rationale for concluding that the requirement of openness must be redefined to include a new sponsorship model.

283. National Grid notes that the rights and obligations of transmission owners in New England to own and construct transmission facilities or upgrades located within or connected to their existing electric systems were extensively litigated in the proceeding where the Commission found that ISO New England satisfied the requirements to be an RTO. National Grid states that in that proceeding, the Commission-approved contractual language in Section 3.09 of ISO New England's Transmission Operating Agreement providing that, absent agreement of ISO New England and the participating transmission owners to an amendment to these provisions, they will be subject to the *Mobile-Sierra* doctrine. Therefore, National Grid argues that the subject provisions cannot be modified by the Commission unless it finds they are contrary to the public interest. It submits that there is no evidence to meet this high standard. National Grid requests that Commission should either clarify that Commission-approved rights to build of transmission owners like those in New England would not be affected by the proposed NOPR requirements, or modify those requirements in the Final Rule to allow transmission owners in New England to continue to meet regional needs under the existing planning process.

c. Commission Determination

284. The Commission determines that it has the authority under section 206 of the FPA to implement the reforms adopted to eliminate provisions in Commission-jurisdictional tariffs and agreements that grant federal rights of first refusal to incumbent transmission

F.3d 477, 484 (DC Cir. 2009); *Mississippi Indus.* v. *FERC,* 808 F.2d 1525, 1542–43 (DC Cir. 1987)).

[257] 295 F.3d 1 (DC Cir. 2002) (*Atlantic City*).

[258] *E.g.,* Oklahoma Gas & Electric; and PPL Companies. In support, Oklahoma Gas & Electric Company cites to *PSI Energy, Inc.,* 55 FERC ¶ 61,254, at 61,811 (1991), *reh'g denied,* 56 FERC ¶ 61,237 (1991).

[259] PPL Companies (citing *CAISO* v. *FERC,* 372 F.3d 395 (DC Cir. 2004)).

[260] In addition, FirstEnergy Service Company states that the court in *CAISO* v. *FERC* explained that a more expansive interpretation of ''practice'' would allow the Commission to regulate a range of subjects that the court considered to be plainly beyond the Commission's authority.

[261] Indicated PJM Transmission Owners (citing *Town of Norwood* v. *FERC,* 80 F.3d 526, 531 (DC Cir. 1996)).

[262] Indicated PJM Transmission Owners (citing *Mo. ex. rel. Southwestern Bell Tel. Co.* v. *Pub. Serv. Comm'n,* 262 U.S. 276, 289 n.1 (1923)). Indicated PJM Transmission Owners also note that Congress did provide similar authority in laws that parallel the FPA, such as section 402 of the Transportation Act of 1920, and sections 5 and 7 of the Natural Gas Act.

[263] *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132, 1148 (DC Cir. 1980).

providers with respect to the construction of transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission's remedial authority under FPA section 206 of the FPA is broad and allows us to act, as we do here, to revise terms in jurisdictional tariffs and agreements that may cause the rates, terms or conditions of transmission service to become unjust and unreasonable or unduly discriminatory or preferential.[264] As explained in the preceding section, granting incumbent transmission providers a federal right of first refusal with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation effectively restricts the universe of transmission developers offering potential solutions for consideration in the regional transmission planning process. This is unjust and unreasonable because it may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, the inclusion of higher-cost solutions in the regional transmission plan. It is squarely within our authority under FPA section 206 to correct this deficiency.

285. A federal right of first refusal is, in the language of section 206(a), a ''rule, regulation, practice, or contract'' affecting the rates for jurisdictional transmission service. Where the Commission finds that such rules, regulations, practices or contracts are ''unjust, unreasonable, unduly discriminatory, or preferential,'' the Commission must determine ''the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.'' In light of our finding above that federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential savings, the Commission is compelled under section 206(a) to take corrective action here. The court in *CAISO* v. *FERC* explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.'' [265] The Commission here is focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on competition and in turn the rates for jurisdictional transmission services. As explained in greater depth below, these matters fall directly within the ambit of the court's interpretation of a practice affecting rates.

286. In addition, federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. The Commission has long recognized that it has a responsibility to consider anticompetitive practices and to eliminate barriers to competition.[266] Indeed, the Supreme Court has said that ''the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest.'' [267] In requiring the elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements, we are acting in accordance with our duty to maintain competition.

287. Eliminating a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, as some commenters contend, result in the regulation of matters reserved to the states, such as transmission construction, ownership or siting. The reforms are focused solely on public utility transmission provider tariffs and agreements subject to the Commission's jurisdiction. While many commenters indicate that they disagree with these statements, none of them has explained adequately how our actions will override or conflict with state laws or regulations. The Commission acknowledges that there may be restrictions on the construction of transmission facilities by nonincumbent transmission providers under rules or regulations enforced by other jurisdictions. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. It does not follow that the Commission has no authority to remove such restrictions in the tariffs or agreements subject to its jurisdiction.

288. The Commission disagrees with commenters arguing that the effect of a federal right of first refusal on jurisdictional rates is too tenuous to support action. These commenters argue that the holding of *CAISO* v. *FERC,*[268] prevents us from treating a federal right of first refusal as a practice that affects transmission rates. In that case, the court held that the Commission has no authority to replace the selection method or membership of the governing board of the California ISO, which had been established under state law.[269] The court found that such internal governance practices were too remote from the California ISO's rate structure to be considered practices that affect rates for purposes of section 206 and, as a result, rejected the Commission's attempt to impose governance requirements that conflicted with state law.[270]

289. Here, however, the Commission is focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on the rates for jurisdictional transmission services and on undue discrimination. This extends well beyond the internal corporate governance matters at issue in *CAISO* v. *FERC.* The federal rights of first refusal at issue in this proceeding can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs and, as a result, increasing the cost of transmission development that is recovered from jurisdictional customers through rates. The selection of transmission facilities in a regional transmission plan for purposes of cost allocation is therefore, unlike corporate governance matters, directly related to costs that will be allocated to jurisdictional ratepayers.

290. Other commenters rely on *Mo. ex. rel. Southwestern Bell Tel. Co.* v. *Pub. Serv. Comm'n* for the proposition that, because a utility has a right to recover prudently incurred costs, it has a corollary right to decide whether to incur those costs, which the Commission cannot violate by eliminating a federal right of first refusal. In that case, the court explained that a utility's right to make investment decisions is grounded in the business judgment rule, which prevents courts from substituting their judgment on the prudence of investment decisions for that of corporate directors and officers.[271] Nothing in that case, however, supports a claim to an exclusive right to make investments under a federal right of first refusal, only the need to defer to business judgment when investment decisions are in fact

[264] *Associated Gas Distributors,* 824 F.2d 981, 1008 (DC Cir. 1985).

[265] *CAISO* v. *FERC,* 372 F.3d 395 at 403.

[266] *Gulf States Utils. Co.,* 5 FERC ¶ 61,066 at 61,098.

[267] *Otter Tail Power Co.* v. *United States,* 410 U.S. 366 at 374 (1973).

[268] 372 F.3d 395 at 399.

[269] *CAISO* v. *FERC,* 372 F.3d 395 at 398.

[270] *Id.* at 403.

[271] *See Mo. ex. rel. Southwestern Bell Tel. Co.* v. *Pub. Serv. Comm'n,* 262 U.S. 276, 289 (1923).

made. In removing a federal right of first refusal from Commission-jurisdictional tariffs and agreements, the Commission is drawing no conclusion regarding the prudence of any investment decision, nor is the Commission seeking to determine which particular entity should construct any particular transmission facility. The effect of these reforms is to allow more types of entities to be considered for potential construction responsibility, not to make choices among those transmission developers or their proposed transmission facilities.

291. The Commission therefore determines that these reforms regarding elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements are not prevented by state law or otherwise limited by the FPA. In directing the removal of a federal right of first refusal from Commission-jurisdictional tariffs and agreements, the Commission is not ordering public utility transmission providers to enlarge their transmission facilities under sections 210 or 211 of the FPA, nor making findings related to our authorities under section 215 or 216. Similarly, nothing in our actions today is inconsistent with our obligations under section 217. Indeed, section 217(b)(4) directs the Commission to exercise its authority ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load serving entities to satisfy [their] load serving obligations.'' Greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load serving entities and increased access to resources.

292. We decline to address at this time the merits of National Grid's arguments that section 3.09 of the ISO New England Transmission Operating Agreement establishes a federal right of first refusal that can be modified only if the Commission makes the findings that National Grid contends are required by application of the *Mobile-Sierra* doctrine.[272] We find that the record is not sufficient to address the specific issues raised by National Grid in this generic proceeding. Moreover, we generally do not interpret an individual contract in a generic rulemaking, and we are not persuaded to do so here given the limited record developed so far on section 3.09. Thus, we conclude that these arguments, including National Grid's argument as to the applicable standard of review, are better addressed as part of the proceeding on ISO New England's compliance filing pursuant to this Final Rule, where interested parties may provide additional information.

3. Removal of a Federal Right of First Refusal From Commission-Jurisdictional Tariffs and Agreements

a. Commission Proposal

293. In the Proposed Rule, the Commission sought comment on a framework to eliminate from a transmission provider's OATT or agreements subject to the Commission's jurisdiction provisions that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities that are included in a regional transmission plan. The Commission proposed to require each public utility transmission provider to revise its OATT to: (1) Establish appropriate qualification criteria for determining an entity's eligibility to propose a project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer; (2) include a form by which a prospective project sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process, and provide a single, specified date by which proposals must be submitted; (3) describe a transparent and not unduly discriminatory or preferential process used by the region for evaluating whether to include a proposed transmission facility in a regional transmission plan; (4) remove, along with corresponding changes in any other Commission-jurisdictional agreement, provisions that establish a federal right of first refusal for an incumbent transmission provider and include a description of how the regional transmission planning process provides a right to construct a selected project to the project sponsor, including potential modifications to proposed projects; (5) provide the right to develop a project for a defined period of time if not initially included in a regional transmission plan; and, (6) provide a comparable opportunity for incumbent and nonincumbent transmission project developers to recover the cost of a transmission facility through a regional cost allocation method.[273]

294. Under this framework, the Commission proposed that neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. The Commission stated that both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan. The Commission proposed that the tariff changes to implement these proposed reforms would be developed through an open and transparent process involving the public utility transmission provider, its customers, and other stakeholders.

295. Given the interrelated nature of comments regarding the first two and the remaining four elements of the Commission's proposed framework, the Commission groups comments accordingly and then turns to addressing the comments collectively.

b. Comments Regarding Developer Qualification and Project Identification

296. A number of commenters address issues related to the first two aspects of the Commission's proposed framework, governing mechanisms by which entities could propose a project in the regional transmission planning process.[274] San Diego Gas & Electric contends that any qualification criteria for potential transmission developers should address all of the technical and financial capabilities necessary for the entity to support the transmission project, if approved, for its expected lifetime, including provisions of security and insurance, as well as other requirements, such as those relating to the proponent's capital structure. Wind Coalition agrees that transmission project developers should be required to satisfy certain financial standards to ensure that they can properly construct and maintain their proposed projects. According to Wind Coalition, the experience of the Competitive

[272] In support of its argument, National Grid cites *ISO New England, Inc.,* 109 FERC ¶ 61,147, at P 78 (2004). In that order, the Commission stated, ''We will grant Mobile-Sierra treatment, as requested by the Filing Parties. Section 3.09 provides direction to the Transmission Owners and the ISO–NE RTO to follow planning procedures contained in the ISO–NE RTO OATT. As such, this provision will have no adverse impact on third parties or the New England market.''

[273] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 90–96.

[274] *E.g.,* American Transmission; Connecticut & Rhode Island Commissions; Federal Trade Commission; Integrys; ISO–NE; Large Public Power Council; MidAmerican; Massachusetts Departments; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; New Jersey Board; NextEra; Northeast Utilities; and Western Independent Transmission Group.

Renewable Energy Zones in ERCOT has demonstrated the need for a selection procedure that provides for: Clearly defined standards for selection; selection within a reasonable time period; and a definite beginning and ending date to avoid unnecessary delay in selection and construction and to prevent a strategy of delay or gamesmanship.

297. Most commenters that weighed in on this issue urge the Commission not to adopt a one-size-fits-all set of requirements and, instead, allow each region to develop criteria appropriate for the region.[275] A number of commenters, however, encourage the Commission to identify the types of criteria that must be addressed to codify expectations and ensure that all entities are operating under the same requirements.[276] Old Dominion recommends that the following criteria be used to evaluate proposers of projects: Financial viability; technical expertise; authority or ability to obtain and meet all necessary regulatory requirements, including condemnation where necessary; and an exit strategy to address how the facilities can or will be transferred if an entity is no longer able to meet financial or other obligations associated with the project. PJM supports a requirement that each project developer demonstrate that it has received up-front authority to site its project from the relevant states because, without such authority, it would be fruitless to designate a project to the prospective project developer. In reply, however, Atlantic Wind Connection disagrees with PJM, instead suggesting that developers receive state siting approval within a reasonable time after selection of the project in a regional transmission plan.

298. While many commenters endorse requiring project developers to meet qualification criteria showing their financing and technical capabilities, some argue that the rules cannot be one-sided against nonincumbents so as to amount to a backdoor right of first refusal.[277] LS Power states, for example, that an entity that is financially qualified but is deemed to not be technically qualified should be permitted to partner with a technically qualified entity. Pattern Transmission states that, if a transmission provider determines that a project developer does not meet the qualification criteria, it should be required to provide the rationale for that determination to the applicant in writing so that any future attempt to meet the qualification criteria will be better informed. Other commenters express concern that the qualification criteria not be so onerous that they cannot be readily satisfied by existing transmission owners.[278] APPA and Transmission Access Policy Group suggest that qualification criteria be crafted in a way that supports a variety of ownership arrangements, including joint ownership by public power systems.

299. Some commenters oppose or otherwise raise concerns regarding the use of qualification criteria to determine eligibility to propose projects in the regional transmission planning process.[279] PPL Companies state that RTOs do not have experience in evaluating the capabilities of nonincumbent transmission developers and that both the establishment and application of the criteria are likely to result in disputes and litigation. Indianapolis Power & Light states that, because incumbents have existing state obligations to serve, incumbent transmission owners should be deemed to meet any qualification criteria without any additional showing. Pacific Gas & Electric similarly argues that qualification criteria should take into consideration the ability of incumbent transmission owners to provide cost and efficiency benefits that may not be available from a single-project transmission owner, such as in obtaining siting and permitting approvals.

300. Several commenters address the use of a form to obtain information from prospective transmission developers as to projects submitted for evaluation in the regional transmission planning process.[280] LS Power asks the Commission to set forth the requisite project information required in such a form, subject to any region or transmission provider obtaining Commission approval to modify such requirements. California ISO suggests that, notwithstanding its general opposition to the elimination of federal rights of first refusal, any requirements imposed on project developers to submit information in support of a proposal should include the submission of sufficient study results evidencing a *prima facie* case that the project is needed. Exelon contends that project proposals should be required to include technical analyses demonstrating that they meet the region's requirements and that a developer should not be provided with any priority rights without such supporting documentation. Transmission Agency of Northern California asks the Commission to clarify that the evaluation form should be developed in the regional transmission planning process and that a project developer would not be required to submit separate and distinct forms to each public utility transmission provider that participates in a given regional transmission planning process.

301. LS Power supports the proposal for public utility transmission providers to identify a specified date by which to submit proposed transmission projects, generally arguing that a submission deadline would promote orderly and fair consideration of projects.[281] Others oppose the proposal, generally arguing that existing transmission planning processes are iterative in nature.[282] For example, New England States Committee on Electricity states that establishing such a deadline could have the unintended consequence of discouraging discussion of emerging needs and alternative ways to meet them. It suggests that the Commission leave such procedural matters to the regions for consideration. Some commenters express concern that the Commission's proposal invites gaming, creating an incentive to propose a host of projects so that individual entities may obtain their own time-based rights of first refusal to develop proposals.[283] LS Power disagrees in reply, arguing that such concerns could be addressed by requiring transmission developers to post a reasonable deposit, which could be based in part on the total estimated cost to develop the annual plan and the number of transmission projects evaluated in the plan, to avoid new projects being filed in an effort to prevent others from developing them.

[275] *E.g.,* New York ISO; Transmission Agency of Northern California; California Commissions; Arizona Public Service Company; Northeast Utilities; and SPP.

[276] *E.g.,* Edison Electric Institute; California ISO; Pacific Gas & Electric; Exelon; Southern California Edison; Southern Companies; PJM; and National Grid.

[277] *E.g.,* Anbaric and PowerBridge; LS Power; and Pattern Transmission; and Primary Power. Anbaric and PowerBridge cite to *New England Indep. Transmission Co., L.L.C.,* 118 FERC ¶ 61,127 (2007).

[278] *E.g.,* New York ISO; Transmission Agency of Northern California; California Commissions; Arizona Public Service Company; Northeast Utilities; and SPP.

[279] *E.g.,* PPL Companies; Indianapolis Power & Light; and Pacific Gas & Electric.

[280] *E.g.,* California ISO; Edison Electric Institute; LS Power; and Transmission Agency of Northern California.

[281] *E.g.,* LS Power.

[282] *E.g.,* Edison Electric Institute; California ISO; ISO New England; NEPOOL; Northeast Utilities; New England States Committee on Electricity; and National Rural Electric Coops.

[283] *E.g.,* Edison Electric Institute; Exelon; MISO Transmission Owners; California ISO; ISO New England; NEPOOL; Northeast Utilities; New England States Committee on Electricity; and National Rural Electric Coops.

c. Comments Regarding Project Evaluation and Selection

302. Commenters also address the remaining four aspects of the Commission's proposed framework for eliminating federal rights of first refusal, relating to mechanisms to evaluate, select and recover the costs of projects proposed in the regional transmission planning process. Most commenters support the proposal that each public utility transmission provider participate in a regional transmission planning process that evaluates the proposals submitted through a transparent and not unduly discriminatory or preferential process.[284] For example, Duke and National Grid state that existing regional transmission planning processes already evaluate proposed projects through an open process described in the relevant public utility transmission providers' OATTs.

303. Several commenters suggest that regional flexibility is needed when determining the procedures by which transmission projects are evaluated and selected.[285] For example, Connecticut & Rhode Island Commissions and Massachusetts Departments state that ensuring equal rights and obligations of incumbent and nonincumbent transmission developers would raise a number of questions that will need to be addressed through the stakeholder process, including how projects and developers are selected, how non-transmission alternatives will be evaluated, how rights of way are negotiated, and how to address cost overruns. They state that the Final Rule should recognize the many issues that would arise following the proposed change and allow the stakeholder process flexibility to identify and develop solutions to these challenges. Western Independent Transmission Group suggests the use of an independent third-party observer may be necessary to oversee the evaluation and selection of competing transmission projects to give market participants and the Commission assurance that the process is fairly and efficiently managed.

304. A number of commenters characterize the Commission's proposal as implementing a sponsorship model that conflicts with the collaborative nature of current transmission planning processes.[286] North Dakota & South Dakota Commissions state that the sponsorship paradigm will turn current transmission planning processes into an unmanageable free for all, undermining the effective evaluation of potential transmission solutions. Integrys and Southern Companies contends that sponsorship rights may do more harm than good and will defeat the objective of an orderly and systematic planning and construction process, increasing disputes, creating queuing problems, disrupting existing OATT processes, harming reliability, and resulting in a loss of flexibility. Baltimore Gas & Electric argues that those that want to claim sponsorship rights also do not want to provide the RTO with discretion to deny their claim and that such entities could tie up transmission construction as long as they want until they ensure they are the builders. National Rural Electric Coops suggest that the Commission convene a technical conference to address complex implementation issues.

305. Southern Companies also question how transmission proposals submitted by nonincumbent transmission providers should be evaluated in the regional transmission planning process. Southern Companies state that the Proposed Rule could be viewed as permitting any qualified entity to sponsor projects at the regional level, where a "black box" evaluation process would be applied to determine the "winners." Southern Companies suggest that nonincumbent transmission developers be treated similarly to the integration of merchant generation so that state law would not be undermined. That is, Southern Companies recommend that, if a nonincumbent transmission developer has a proposal that the incumbent utility believes to be cost-effective and reliable, that developer would have to join with Southern Companies to petition the relevant state regulatory authorities for approval for construction and rate recovery.

306. Some commenters argue that the Commission should not require development of mechanisms that provide construction rights to nonincumbent transmission developers seeking to develop projects solely within an existing transmission owner's footprint or that use rights-of-way held by existing transmission owners.[287] For example, Edison Electric Institute asks the Commission to clarify that only an incumbent transmission owner should be allowed to propose local, single system facilities that are simply rolled up into a regional plan, as well as upgrades or modifications to facilities owned by an incumbent transmission provider, including reconductoring, tower change outs, additional facilities in existing substations, facilities in a right of way owned by the incumbent, and new substations cut into existing lines. It argues that allowing nonincumbent transmission developers to perform upgrades to an incumbent transmission owner's transmission facilities could delay upgrades necessary to maintain system reliability and increase the costs of constructing and maintaining such transmission facilities. PJM agrees, arguing that existing transmission owners are in the best position to use their own resources. Imperial Irrigation District expresses concern regarding the potential impact of the Proposed Rule on contractual rights in existing joint ownership and operation agreements governing existing facilities. LS Power cautions that, to the extent the Commission provides for the retention of federal rights of first refusal for existing facilities, the limitations of such an exclusion must be clearly described in the OATT.

307. A number of commenters suggest that the Commission modify the proposal for sponsors of proposed transmission projects to retain the right to build projects of a similar scope for a defined period of time.[288] Bonneville Power states that this proposed reform creates the potential for increased litigation to determine whether an incumbent transmission owner's project is substantially similar to a previously proposed non-incumbent transmission developer's project. Xcel and others[289] contend that selection among similar projects for inclusion in the regional transmission plan is inherently subjective and, therefore, determining whether a project is a modification of a previously proposed project or sufficiently different to be considered a

[284] *E.g.,* Federal Trade Commission; PUC of Nevada; Massachusetts Departments; New England States Committee on Electricity; California Commissions; Connecticut & Rhode Island Commissions; LS Power; FirstWind; National Grid; Western Independent Transmission Group; Transmission Agency of Northern California; Northern California Power Agency; Pattern Transmission; American Transmission; California State Water Project; Anbaric and PowerBridge; PPL Companies; Green Energy and 21st Century; Duke; and Old Dominion.

[285] *E.g.,* Connecticut & Rhode Island Commissions; National Grid; New England States Committee on Electricity; KCP&L; Edison Electric Institute; and WIRES.

[286] *E.g.,* Baltimore Gas & Electric; Edison Electric Institute; Integrys; MISO Transmission Owners; North Dakota & South Dakota Commissions; PSEG Companies; PPL Companies; and Southern Companies.

[287] *E.g.,* Anbaric and PowerBridge; California Municipal Utilities; Edison Electric Institute; Exelon; Imperial Irrigation District; LS Power; PJM; and Southern California Edison.

[288] *E.g.,* California Municipal Utilities; Exelon; LS Power; Northern Tier Transmission Group; and Transmission Agency of Northern California.

[289] *E.g.,* Duke; PPL Companies; MidAmerican; and North Dakota and South Dakota Commissions.

new project would be difficult. National Rural Electric Coops ask the Commission to clarify that the proposal does not prevent an incumbent transmission provider from making minor modifications to a competing transmission project to better meet the needs of the participants in the process.

308. Some commenters argue that the Commission should implement competitive bidding processes for selecting project developers instead of relying on a sponsor-based mechanism for determining construction rights.[290] For example, Transmission Access Policy Study Group contends that competitive bidding yields lower costs to consumers, includes mechanisms to limit cost overruns, and restricts the ability of winning bidders to transfer construction rights. It suggests that any competitive bidding process employed by the Commission favor projects that are jointly owned. California ISO states that its competitive solicitation framework for economic and public policy transmission projects meets the Commission's goals of ensuring development of cost-effective transmission facilities, providing ratepayer benefits, optimizing participation in the transmission planning process, and providing opportunities for nonincumbent transmission developers, although California ISO opposes the use of competitive solicitations for reliability projects. Edison Electric Institute and Ad Hoc Coalition of Southeastern Utilities contend that mandating competitive bidding would undermine existing transmission planning processes and allow nonincumbent developers to bid selectively only for advantageous projects. Pattern Transmission responds that such ''cherry picking'' concerns can be addressed through properly structured competitive bidding processes.

309. With regard to the period for which development rights could be retained, LS Power recommends that a transmission developer that sponsors a transmission project be permitted to retain the right to build or build and own the transmission project for a minimum of five years, while California Municipal Utilities suggest a period of two years. Others express concern with the impact of the Commission's proposal, generally arguing such a policy would encourage entities to submit multiple proposals to maximize potential development opportunities.[291] For example, National Rural Electric Coops suggest this would create an approach to transmission planning in which immutable transmission proposals compete against each other in a form of baseball arbitration (in which the arbitrator must pick one side's offer without modification), even if minor changes to one or more of the proposals would allow them to better meet the needs of consumers in the region. LS Power and Transmission Agency of Northern California disagree, arguing that objective rules can be established to identify when a modified project is the functional equivalent of a sponsored project.

310. Arizona Corporation Commission stresses that, in all cases, proposed transmission projects resubmitted for consideration must be freshly evaluated in each transmission planning cycle so that projects address current needs and requirements. Northern Tier Transmission Group recommends that a project that is not selected in the regional transmission plan must have similar performance characteristics and costs when resubmitted for consideration. California Municipal Utilities argue that a project sponsor should not receive a priority right during resubmission if the transmission project sponsor is only interested in selling that right.

311. Some commenters seek clarification of the obligations that would be imposed on nonincumbent transmission developers as a result of selection of its project for construction.[292] MISO Transmission Owners and New York Transmission Owners contend that, if the proposed reforms are implemented, the Commission should make clear that a nonincumbent transmission developer's right to participate in the transmission planning process must be accompanied by an obligation that it satisfy all the requirements expected of transmission developers in the regional transmission planning process. MISO Transmission Owners state that this clarification is particularly important because institutional investors may seek to invest in transmission facilities to earn the stable return on their investment that a rate-regulated business would provide but have no intention to become public utilities once the facility is placed into service and put under the functional control of an RTO. Minnesota PUC and Minnesota Office of Energy Security suggest that winning transmission projects, regardless of ownership type, should be subject to regulatory scrutiny to make sure that when completed the transmission project fulfills the needs initially ascribed to it and that the transmission project costs are consistent with the cost levels initially proposed.

312. Finally, commenters also address whether the selection of a transmission facility proposed by a nonincumbent transmission developer for inclusion in the regional transmission plan should be eligible for regional cost allocation.[293] Massachusetts Departments and Connecticut & Rhode Island Commissions agree with the basic principle, but argue that recovery should be determined by project criteria and not on the basis of the type of developer proposing the project. SPP and Old Dominion support the proposal, provided that the nonincumbent transmission developer is subject to the same responsibilities as incumbent transmission owners pursuant to the transmission planning requirements. MISO Transmission Owners raise the possibility that a nonincumbent project selected in the regional transmission planning process may be rejected by a state agency in favor of an incumbent transmission owner and question whether under this scenario an incumbent transmission owner would be required to build the project but would not be eligible for regional cost recovery. Ad Hoc Coalition of Southeastern Utilities assert that the proposal may conflict with state-based mandates, explaining that the majority of transmission costs in the Southeast are incurred to serve native load, and are included in rates established pursuant to state or local regulation.

d. Commission Determination

313. The Commission directs public utility transmission providers, subject to the modifications to the Proposed Rule discussed below and subject to the framework discussed and adopted below, to eliminate provisions in Commission-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a

[290] *E.g.,* Transmission Access Policy Study Group; Pattern Transmission; and Indianapolis Power & Light.

[291] *E.g.,* Connecticut & Rhode Island Commissions; Indianapolis Power & Light; Indicated PJM Transmission Owners; Massachusetts Departments; National Rural Electric Coops; and Oklahoma Gas & Electric.

[292] *E.g.,* New York Transmission Owners; Edison Electric Institute; MISO Transmission Owners; Southern Companies; and Transmission Agency of Northern California.

[293] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; FirstEnergy Service Company; MISO Transmission Owners; New York ISO; Old Dominion; and SPP.

regional transmission plan for purposes of cost allocation.

314. As explained in the preceding sections, the elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements is necessary and appropriate to ensure that rates for jurisdictional services are just and reasonable. However, based on the comments received in response to the Proposed Rule, the Commission modifies the specific requirements placed on public utility transmission providers to implement the proposal and provides clarification regarding those requirements to facilitate compliance.[294]

315. To place our actions in context, the Commission reiterates the existing requirements of Order No. 890 as implemented by public utility transmission providers. As noted by commenters, Order No. 890 already requires public utility transmission providers to have in place processes for evaluating the merits of proposed transmission solutions offered by potential developers.[295] To ensure comparable treatment of all resources, the Commission has required public utility transmission providers to include in their OATTs language that identifies how they will evaluate and select among competing solutions and resources.[296] This includes the identification of the criteria by which the public utility transmission provider will evaluate the relative economics and effectiveness of performance for each alternative offered for consideration.[297] Given that the regions already have processes in place to evaluate competing transmission projects in their transmission planning process, the fundamental question raised in the Proposed Rule is whether additional requirements are needed to ensure that these processes are not adversely affected by federal rights of first refusal. The Commission concludes that such requirements are necessary and, accordingly, adopts the framework set forth in the Proposed Rule with modification.

316. Opponents of the Commission's proposed elimination of federal rights of first refusal argue that this framework represents a fundamental shift in the way that transmission is planned in existing regional processes. These commenters contend that characterizing existing transmission owners as developers of sponsored transmission facilities that are to be evaluated on a comparable basis to proposals submitted by nonincumbent transmission developers transforms, in their view, the collaborative and iterative transmission planning process into a sponsorship-driven competition for new investment opportunities. As we explain elsewhere, the reforms adopted in this Final Rule build upon the requirements of Order No. 890 with respect to transmission planning. Public utility transmission providers already have put in place mechanisms to provide for comparative evaluation of competing solutions. We recognize that the mechanisms for evaluating proposals under this Final Rule will have greater implications because we are also requiring a just and reasonable and not unduly discriminatory process to grant to a transmission developer the ability to use the regional cost allocation method associated with each transmission facility selected in the regional transmission plan for purposes of cost allocation. However, we disagree that the reforms in the Proposed Rule, as modified herein, will make the planning process unmanageable, as suggested by some commenters.

317. Some of the concerns expressed by commenters appear to be driven by the phrasing used in the Proposed Rule to present the framework for removing federal rights of first refusal. There, the Commission stated that both incumbent and nonincumbent transmission developers should share similar benefits and obligations, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan.[298] The Commission's focus in the Proposed Rule on sponsorship of proposed transmission facilities, whether by incumbent transmission providers or nonincumbent transmission developers, appears to have led many commenters to conclude that every transmission facility being planned by an incumbent transmission provider is, in effect, sponsored by that entity and, therefore, could no longer be subject to a federal right of first refusal. The Commission clarifies that this was not the intent of the Proposed Rule, nor is it the intent of the requirements adopted in this Final Rule.

318. The Commission's focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation.[299] As Edison Electric Institute notes, in those regions relying on ''bottom up'' local transmission planning, a transmission facility that is in a public utility transmission provider's local transmission plan might be ''rolled-up'' and listed in a regional transmission plan to facilitate analysis at the regional level. However, the transmission facility from the local transmission plan might not have been proposed in the regional transmission planning process and might not have been selected in the regional transmission plan for purposes of cost allocation by going through an analysis in the regional transmission planning process. The Commission does not, in this Final Rule, require removal from Commission-jurisdictional tariffs and agreements of a federal right of first refusal as applicable to a local transmission facility, as that term is defined herein.[300]

319. In addition, the Proposed Rule emphasized that our reforms do not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation.[301] In other words, an incumbent transmission provider would be permitted to maintain a federal right of first refusal for upgrades to its own transmission facilities. In addition, the Commission affirms that proposal here, and in response to commenters adds that our reforms are not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way. That is, this Final Rule does not remove or limit any right an incumbent may have to build, own and

[294] The requirements adopted here apply only to public utility transmission providers that have provisions in their tariffs or other Commission-jurisdictional agreements granting a federal right of first refusal that is inconsistent with the requirements of this Final Rule. If no such provisions are contained in a public utility transmission provider's tariff or other Commission-jurisdictional agreement, it should state so in its compliance filing.

[295] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494; Order No. 890–A, FERC Stats. & Regs. ¶ 61,297 at P 215–16.

[296] *See, e.g., New York Independent System Operator, Inc.,* 129 FERC ¶ 61,044 at P 35.

[297] *Id.*

[298] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 93.

[299] In order for a transmission facility to be eligible for the regional cost allocation methods, the region must select the transmission facility in the regional transmission plan for purposes of cost allocation. For those facilities not seeking cost allocation, the region may nonetheless have those transmission facilities in its regional transmission plan for information or other purposes, and then having such a facility in the plan would not trigger regional cost allocation.

[300] *See* definition *supra* section II.D of this Final Rule.

[301] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 97.

recover costs for upgrades to the facilities owned by an incumbent, nor does this Final Rule grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation. The retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way.

320. Through the reforms to regional planning required in this Final Rule, the Commission is seeking to ensure that a robust process is in place to identify and consider regional solutions to regional needs, whether initially identified through ''top down'' or ''bottom up'' transmission planning processes. Combined with the cost allocation and other reforms adopted in this Final Rule, implementation of this framework to remove federal rights of first refusal will address disincentives that may be impeding participation by nonincumbent transmission developers in the regional transmission planning process. The extent to which any existing regional transmission planning process must be changed to implement the framework set forth below will depend on the mechanisms used by the region to evaluate competing transmission projects and developers.

321. For example, this Final Rule permits a region to use or retain an existing mechanism that relies on a competitive solicitation to identify preferred solutions to regional transmission needs, and such an existing process may require little or no modification to comply with the framework adopted in this Final Rule.[302] In regions relying primarily on ''top down'' mechanisms pursuant to which regional planners independently identify regional needs and more efficient and cost-effective solutions, existing procedures that allow for stakeholders to offer potential solutions for consideration could provide a foundation for implementing the framework below. In other regions emphasizing the development of local transmission plans prior to analysis at the regional level of alternative solutions, additional procedures may be required to distinguish between those transmission facilities that are proposed to be selected in the regional transmission plan for purposes of cost allocation and those that are merely ''rolled up'' for other purposes.

322. The Commission concludes that the framework adopted below provides sufficient flexibility for public utility transmission providers in each region to determine, in the first instance, how best to address the removal of federal rights of first refusal from Commission-jurisdictional tariffs and agreements. Because we are allowing for regional flexibility and encouraging stakeholders to participate fully in the implementation of this framework by public utility transmission providers, we decline to decide in this Final Rule to convene a technical conference to further explore issues related to federal rights of first refusal, as suggested by some commenters. With the foregoing background in mind, the Commission turns to the specific requirements of this framework below.

i. Qualification Criteria To Submit a Transmission Project for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

323. First, the Commission requires each public utility transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer. These criteria must not be unduly discriminatory or preferential. The qualification criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate and maintain transmission facilities.

324. The Commission agrees with commenters that qualification criteria are necessary, and that adoption of one-size-fits-all requirements would not be appropriate. It is important that each transmission planning region have the flexibility to formulate qualification criteria that best fit its transmission planning processes and addresses the particular needs of the region. Such criteria could address a range of issues raised by commenters, such as commitments to be responsible for operation and maintenance of a transmission facility.[303] The Commission stresses, however, that appropriate qualification criteria should be fair and not unreasonably stringent when applied to either the incumbent transmission provider or nonincumbent transmission developers. The qualification criteria should allow for the possibility that an existing public utility transmission provider already satisfies the criteria and should allow any transmission developer the opportunity to remedy any deficiency. Within these general parameters, we leave it to each region to develop qualification criteria that are workable for the region, including procedures for timely notifying transmission developers of whether they satisfy the region's qualification criteria and opportunities to mitigate any deficiencies.[304]

ii. Submission of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

325. Second, the Commission requires that each public utility transmission provider revise its OATT to identify: (a) The information that must be submitted by a prospective transmission developer in support of a transmission project it proposes in the regional transmission planning process; and (b) the date by which such information must be submitted to be considered in a given transmission planning cycle. The Commission declines to adopt the proposal to require a specific form to be developed for the purpose of submitting this information, given that the data to be submitted may not be easily reduced

[302] For example, the Commission has found that competitive solicitation processes can provide greater potential opportunities for independent transmission developers to build new transmission facilities. *See, e.g., California Indep. Sys. Operator,* 133 FERC ¶ 61,224 (2010). However, the Commission declines to adopt commenter suggestions to mandate a competitive bidding process for selecting project developers. While the Commission agrees that a competitive process can provide benefits to consumers, we continue to allow public utility transmission providers within each region to determine for themselves, in consultations with stakeholders, what mechanisms are most appropriate to evaluate and select potential transmission solutions to regional needs.

[303] The Commission notes, however, that nothing in the qualification requirement of this Final Rule precludes a transmission developer from entering into voluntary arrangements with third parties, including any interested incumbent transmission provider, to operate and maintain a transmission facility. Similarly, nothing this Final Rule creates an obligation for an incumbent transmission provider to operate and maintain a transmission facility developed by another transmission developer. Additionally, nothing in the qualifications requirement of this Final Rule is intended to change any existing RTO or ISO procedure or practice regarding the operation of one or more existing transmission facilities.

[304] To be clear, the qualification criteria required herein should not be applied to an entity proposing a transmission project for consideration in the regional transmission planning process if that entity does not intend to develop the proposed transmission project. The Order No. 890 transmission planning requirements allow any stakeholder to request that the transmission provider perform an economic planning study or otherwise suggest consideration of a particular transmission solution in the regional transmission planning process.

to entries on a form. To ensure consistency in the region, however, the Commission requires each public utility transmission provider that has its own OATT to have in that OATT the same information requirements as other public utility transmission providers in the same transmission planning region, as requested by Transmission Agency of Northern California.

326. These information requirements must identify in sufficient detail the information necessary to allow a proposed transmission project to be evaluated in the regional transmission planning process on a basis comparable to other transmission projects that are proposed in the regional transmission planning process. They may require, for example, relevant engineering studies and cost analyses and may request other reports or information from the transmission developer that are needed to facilitate evaluation of the transmission project in the regional transmission planning process. Beyond these minimum requirements, the Commission provides each region with discretion to identify the information to be required, so long as such requirements are fair and not so cumbersome as to effectively prohibit transmission developers from proposing transmission projects, yet not so relaxed that they allow for relatively unsupported proposals. Whether the region wishes to require *prima facie* showings of need for a project, as suggested by the California ISO, should be addressed in the first instance by public utility transmission providers in consultation with stakeholders within the region. The Commission will review the resulting information requirements on compliance and provide further guidance at that time, if necessary.

327. The Commission disagrees that requiring the identification of a date by which information must be submitted for consideration in a given transmission planning cycle undermines the iterative nature of transmission planning or amounts to creation of a time-based federal right of first refusal. Without some reasonable limitation on the submission of new information, public utility transmission providers would never be able to complete the analysis needed to complete their region's transmission plan. However, each region may determine for itself what deadline is appropriate, including potentially the use of rolling or flexible dates to reflect the iterative nature of their transmission planning processes. Given our decision to eliminate the proposed ongoing right to develop previously-sponsored transmission projects, the Commission believes it is not necessary to require here additional procedural protections such as the posting of deposits, as suggested by LS Power. To the extent stakeholders in a particular region believe such procedures have merit, they may consider them during the development of OATT proposals that comply with the requirement of this Final Rule.

iii. Evaluation of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

328. Third, the Commission requires each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation. This process must comply with the Order No. 890 transmission planning principles, ensuring transparency, and the opportunity for stakeholder coordination. The evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation. In complying with this requirement, the Commission encourages public utility transmission providers to build on existing regional transmission planning processes that, consistent with Order Nos. 890 and 890–A, already set forth the criteria by which the public utility transmission provider evaluates the relative economics and effectiveness of performance for alternative solutions offered during the transmission planning process.

329. In light of comments received in response to the Proposed Rule, we also require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations. We appreciate that there are many sources of delay that could affect the timing of transmission development, and do not intend to require constant reevaluation of delays that do not materially affect the ability of an incumbent transmission provider to meet its reliability needs or service obligations. Our focus here is on ensuring that adequate processes are in place to determine whether delays associated with completion of a transmission facility selected in a regional transmission plan for purposes of cost allocation have the potential to adversely affect an incumbent transmission provider's ability to fulfill its reliability needs or service obligations. Under such circumstances, an incumbent transmission provider must have the ability to propose solutions that it would implement within its retail distribution service territory or footprint that will enable it to meet its reliability needs or service obligations. If such other solution is a transmission facility, public utility transmission providers in the regional transmission planning process should evaluate the proposed solution for possible selection in the regional transmission planning process for purposes of cost allocation. As we have explained elsewhere in this Final Rule,[305] nothing herein restricts an incumbent transmission provider from developing a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.

330. The Commission appreciates that the selection of any transmission facility in the regional transmission plan for purposes of cost allocation requires the careful weighing of data and analysis specific to each transmission facility and, in some instances, may be difficult or contentious. While the Commission appreciates the challenges presented by such an evaluation, the requirement to engage in a comparative analysis of proposed solutions to regional needs has been in place since Order No. 890. The Commission encourages public utility transmission providers to consider ways to minimize disputes, such as through additional transparency mechanisms, as they identify enhancements to regional transmission planning processes necessary to comply with this Final Rule.[306] The Commission declines, however, to mandate the use of independent third-party observers, as suggested by Western Independent Transmission Group. To the extent public utility transmission

[305] *See supra* P 256.

[306] Additionally, as described in section III.A, the requirements of the dispute resolution principle order of Order No. 890 apply to the regional transmission planning process as reformed by this Final Rule.

providers in consultation with other stakeholders in a region wish, they may propose to use an independent third-party observer and we will review any such proposal on compliance.

331. By requiring the evaluation of proposed transmission solutions in the regional transmission planning process, the Commission is not dictating that any particular proposals be accepted or that selected transmission facilities be constructed. Similar to the planning requirements of Order No. 890, the Commission requires the establishment of processes to evaluate potential solutions to regional transmission needs, with the input of interested parties and stakeholders. Whether or not public utility transmission providers within a region select a transmission facility in the regional transmission plan for purposes of cost allocation will depend in part on their combined view of whether the transmission facility is an efficient or cost-effective solution to their needs.[307] Moreover, the Commission anticipates that the processes for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation will vary from region to region, just as other aspects of the regional transmission planning processes may vary.

iv. Cost Allocation for Projects Selected in the Regional Transmission Plan for Purposes of Cost Allocation

332. The Commission also requires that a nonincumbent transmission developer must have the same eligibility as an incumbent transmission developer to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation. More specifically, each public utility transmission provider must participate in a regional transmission planning process that provides that the nonincumbent developer has an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods. As explained further in section IV.C, the cost of a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation, whether proposed by an incumbent or by a nonincumbent transmission provider, may not be recovered through a transmission planning region's cost allocation method or methods.

333. In the Proposed Rule, the Commission acknowledged that a proposed transmission project can be modified in the regional transmission planning process as needs and potential solutions are analyzed and, therefore, sought comment on whether to require a mechanism to identify the most similar project to one initially proposed to determine which developer should have the right to construct and own the facility. Although the Commission raised this issue in the context of processes of construction rights, similar issues are raised regarding the selection of a transmission facility in the regional transmission plan for purposes of cost allocation.

334. In light of the comments received in response to this aspect of the Proposed Rule, we are concerned that the proposed requirement to identify the most similar project to one initially proposed could conflict with the way potential solutions are evaluated and selected in some regions. For example, a requirement to identify proposals that are ''most similar'' to transmission projects in the regional transmission plan may be meaningless in a region that relies on market proposals or competitive solicitations to identify solutions to the region's needs. In other regions that rely on voluntary construction decisions for transmission facilities in a regional transmission plan, the linking of rights to construct to a determination of similarity may be meaningless. As discussed in the next section, in response to concerns such as these, we have decided not to adopt the proposal that would give a sponsor the federal right to construct and own a transmission facility it sponsored consistent with state or local laws or regulations. Given this change, we do not adopt the proposal to require a mechanism to identify the most similar project to one initially proposed to determine which developer should have the right to construct and own the facility.

335. Instead, we adopt and clarify the requirement that a nonincumbent transmission developer of a transmission facility selected in the regional transmission plan for purposes of cost allocation have the same opportunity as an incumbent transmission developer to allocate the cost of such transmission facilities through a regional cost allocation method or methods. We require that each public utility transmission provider must participate in a regional transmission planning process that makes each transmission facility selected in the regional transmission plan for purposes of regional cost allocation eligible for such cost allocation. In other words, eligibility for regional cost allocation is tied to the transmission facility's selection in the regional transmission plan for purposes of cost allocation and not to a specific sponsor.

336. We also require that public utility transmission providers in a region establish, in consultation with stakeholders, procedures to ensure that all projects are eligible to be considered for selection in the regional transmission plan for purposes of cost allocation. This mechanism could be, for example, a non-discriminatory competitive bidding process. The mechanism a regional planning process implements could also allow the sponsor of a transmission project selected in the regional transmission plan for purposes of cost allocation to use the regional cost allocation method associated with the transmission project. In that case, however, the regional transmission planning process would also need to have a fair and not unduly discriminatory mechanism to grant to an incumbent transmission provider or nonincumbent transmission developer the right to use the regional cost allocation method for unsponsored transmission facilities selected in the regional plan for purposes of cost allocation. There may also be other mechanisms, or combinations of mechanisms, that may comply with our requirements.

337. The Commission declines commenter requests to further define the particular obligations and responsibilities that may flow from selection of a nonincumbent transmission developer's proposal in the regional transmission plan for purposes of cost allocation. Nothing in this Final Rule is intended to change or limit any obligations that would apply to a nonincumbent transmission developer under state or local laws or under RTO or ISO agreements.

v. Rights To Construct and Ongoing Sponsorship

338. The Proposed Rule also sought comment on whether to include two additional features in a framework to implement the elimination of federal rights of first refusal: Whether to require public utility transmission providers to revise their OATTs to contain a regional transmission planning process that

[307] As noted above, for one solution to be chosen over another in the regional transmission planning process, there should be an evaluation of the relative efficiency and cost-effectiveness of each solution. If a nonincumbent transmission developer is unable to demonstrate that its proposal is the most efficient or cost-effective, given all aspects of its proposal, then it is unlikely to be selected as the preferred transmission solution within the regional transmission planning process for purposes of cost allocation.

provides a right to construct and own a transmission facility; and, whether to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that is not selected.[308] The Commission declines to adopt these aspects of the Proposed Rule.

339. In the preceding sections, the Commission adopted a framework in which, upon selection of a transmission facility in a regional transmission plan for purposes of cost allocation, the developer of that transmission facility (whether incumbent or nonincumbent) will have the ability to rely on the relevant cost allocation method or methods within the region should it desire to move forward with its transmission project. Nothing in this Final Rule preempts or limits any obligations or requirements that a nonincumbent transmission developer may be subject to under state or local laws or regulations or under RTO or ISO agreements.

340. With regard to ongoing sponsorship rights, the Commission concludes on balance that granting transmission developers an ongoing right to build sponsored transmission projects could adversely impact the transmission planning process, potentially leading to transmission developers submitting a multitude of possible transmission projects simply to acquire future development rights. The Commission appreciates that not granting such a right causes some risk for transmission developers in disclosing their transmission projects for consideration in the regional transmission planning process. That risk is outweighed, however, by the potentially negative impacts such a rule could have on regional transmission planning.

4. Reliability Compliance Obligations of Transmission Developers

a. Comments Regarding Reliability Obligations

341. PSEG Companies and Indianapolis Power & Light contend that it is unclear how compliance with NERC reliability standards would be managed and whether and to what extent a third-party developer would be responsible for NERC compliance, coordination of outages, and whether it would need to become a member or transmission owner in an RTO. PSEG Companies also assert that third party developers are not regulated by state commissions and are not subject to state law obligations with respect to reliability and safety or state law oversight of their operations. Salt River Project argues that mandatory compliance with NERC reliability standards places added pressure on transmission owners and operators to be involved in every stage of planning, construction, and obligation. It asserts that the Proposed Rule was silent as to whether the proposed rules might work with respect to nonincumbent developers that are subsidized for the project but who then may not be interested or qualified to operate or own the facility, let alone comply with reliability standards. Indianapolis Power & Light also expresses concern that questions will remain regarding whether and to what extent a nonincumbent transmission developer is required to comply with NERC reliability standards. Other commenters respond that incumbent transmission owners and nonincumbent transmission developers are subject to and have to meet the same reliability standards.[309]

b. Commission Determination

342. As discussed in section III.B.3 above, the Commission concludes that potentially increasing the number of asset owners through the elimination of a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, by itself, make it more difficult for system operators to maintain reliability. The Commission acknowledges, however, that a proposed transmission facility's impact on reliability is an important factor that is considered during evaluation of a proposed transmission facility for potential selection. We note that, when a nonincumbent transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it will be required to comply with all applicable reliability obligations, as every other registered entity is required. As part of that process, all entities, incumbent and nonincumbents alike, that are users, owners or operators of the electric bulk power system must register with NERC for performance of applicable reliability functions.

343. However, if there are still concerns regarding the lack of clarity as to when compliance with NERC registration and reliability standards would be triggered, we conclude that the appropriate forum to raise these questions and request clarification is the NERC process.

344. The Commission is sensitive to the concerns of some commenters that contend that existing transmission providers run the risk of violating NERC reliability standards in the event that a nonincumbent transmission developer abandons a transmission facility meant to address a violation. To address such concerns, the Commission clarifies that, if a violation of a NERC reliability standard would result from a nonincumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent transmission provider does not have the obligation to construct the nonincumbent's project. Rather, the transmission provider must identify the specific NERC reliability standard(s) that will be violated and submit a NERC mitigation plan to address the violation. Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.

C. Interregional Transmission Coordination[310]

345. This section of the Final Rule adopts several reforms to improve coordination among public utility transmission planners with respect to the coordination of interregional transmission facilities. Specifically, the Commission requires each public utility transmission provider, through its regional transmission planning process, to enhance existing regional transmission planning processes in the following ways.[311] First, the Commission requires the development and implementation of procedures that provide for the sharing of information regarding the respective needs of neighboring transmission planning regions, as well as the identification and joint evaluation by the neighboring transmission planning regions of

[308] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 95.

[309] *E.g.,* City of Santa Clara; Federal Trade Commission; NextEra; Northern California Power Agency; Pattern Transmission; and Western Independent Transmission Group.

[310] We note that our use of the term ''coordination'' with regard to the identification and evaluation of interregional transmission facilities is distinct from the type of coordination of system operations discussed in connection with section 202(a) of the FPA. *See supra* section III.A.2.

[311] In the Proposed Rule, the Commission sometimes referred to the requirements of this section as ''interregional transmission planning''; however, we believe that ''interregional transmission coordination'' better describes what we are requiring in this Final Rule and, therefore, we will refer herein to ''interregional transmission coordination.''

potential interregional transmission facilities that address those needs. Second, to ensure that developers of interregional transmission facilities have an opportunity for their transmission projects to be evaluated, the Commission requires the development and implementation of procedures for neighboring public utility transmission providers to identify and jointly evaluate transmission facilities that are proposed to be located in both regions. Third, to facilitate the joint evaluation of interregional transmission facilities, the Commission requires the exchange of planning data and information between neighboring transmission planning regions at least annually. Finally, to ensure transparency in the implementation of the foregoing requirements, the Commission requires public utility transmission providers, either individually or through their transmission planning region, to maintain a Web site or e-mail list for the communication of information related to interregional transmission coordination.

346. Through these reforms, the Commission aims to facilitate the identification and evaluation of interregional transmission facilities that may resolve the individual needs of neighboring transmission planning regions more efficiently and cost-effectively. To accomplish these reforms, public utility transmission providers in each pair of transmission planning regions are directed to work through their regional transmission planning processes to develop the same language to be included in each public utility transmission provider's OATT that describes the procedures that a particular pair of transmission planning regions will use to satisfy the foregoing requirements. Alternatively, if the public utility transmission providers so choose, these procedures may be reflected in an interregional transmission planning agreement among the public utility transmission providers within neighboring transmission planning regions that is filed with the Commission.[312]

1. Need for Interregional Transmission Coordination Reform [313]

a. Commission Proposal

347. In Order No. 890, the Commission found that, when transmission providers engage in regional transmission planning, they may identify solutions to regional needs that are more efficient than those that would have been identified if needs and potential solutions were evaluated only independently by each individual transmission provider.[314] In Order No. 890–A, the Commission reiterated that effective regional transmission planning must include coordination among transmission planning regions. To that end, the Commission required public utility transmission providers within each transmission planning region to coordinate as necessary to share data, information, and assumptions to maintain reliability and allow customers to consider resource options that span a region.[315]

348. The Commission noted in the Proposed Rule that, within the Order No. 890 and 890–A framework, transmission providers in certain parts of the country have organized subregional transmission planning groups for the purpose of collectively developing transmission plans for facilities on their combined transmission systems. These subregional transmission plans are then analyzed at a regional level to ensure that, if implemented, they will be simultaneously feasible and meet reliability requirements. The Commission also acknowledged that some neighboring transmission planning regions have undertaken joint transmission planning pursuant to bilateral agreements.[316]

349. However, the October 2009 Notice observed that there are few processes in place to analyze whether alternative interregional solutions more efficiently or effectively would meet the needs identified in individual regional transmission plans. As part of the October 2009 Notice, the Commission posed several questions related to this issue, including whether existing transmission planning processes are adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers. The Commission also sought comment as to what processes should govern the identification and selection of projects that affect multiple systems.

350. In light of the comments received on this issue, the Commission in the Proposed Rule expressed concern that the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential. The Commission noted that, in the few years since the issuance of Order No. 890, interest in multiregional transmission facilities has grown significantly.[317] Therefore, the Commission proposed reforms intended to improve coordination between neighboring transmission planning regions with respect to the evaluation of transmission facilities that are proposed to be located in both regions, as well as other possible interregional transmission facilities, to determine if such facilities address the needs of the transmission planning regions more efficiently or cost-effectively.[318]

b. Comments

351. Many commenters agree that there is a need to increase coordination in interregional transmission planning,[319] and identified a range of deficiencies in and opportunities for enhancement of existing interregional transmission coordination efforts. Several commenters state that a more defined and coordinated interregional transmission planning process is

[312] We discuss the filing requirements for the same language to be included in each public utility transmission provider's OATT that describes the procedures that a particular pair of transmission planning regions will use to satisfy the interregional transmission coordination requirements as well as for any interregional transmission coordination agreements in the compliance section below. *See* discussion *infra* section III.C.3.e. of this Final Rule.

[313] Legal authority issues associated with the interregional transmission coordination reforms described herein are addressed in the discussion above concerning regional transmission planning. *See* discussion *supra* section III.A.2. of this Final Rule.

[314] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[315] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 226.

[316] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 103.

[317] The Commission cited two such recent multiregional projects. *Id.* n.46 (citing *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281 (2009); *Green Power Express LP,* 127 FERC ¶ 61,031 (2009)).

[318] *Id.* P 112–113.

[319] *E.g.,* AEP; Allegheny Energy Companies; AWEA; CapX2020 Utilities; Clean Line; Duke; East Texas Cooperatives; Edison Electric Institute; Energy Future Coalition; Environmental Defense Fund; Exelon; Federal Trade Commission; First Energy Service Company; Integrys; ISO New England; ITC Companies; Kansas City Power & Light and KCP&L Greater Missouri; LS Power; Massachusetts Departments; MidAmerican; MISO; MISO Transmission Owners; Minnesota PUC and Minnesota Office of Energy Security; National Grid; Natural Resources Defense Council; NEPOOL; New York ISO; NextEra; Northeast Utilities; Old Dominion; Organization of MISO States; Pattern Transmission; Pennsylvania PUC; PHI Companies; Pioneer Transmission; Powerex; PSEG Companies; PUC of Nevada; San Diego Gas & Electric; Sonoran Institute; Sunflower and Mid-Kansas; Transmission Access Policy Study Group; Vermont Electric; Westar; Wilderness Society and Western Resource Advocates; WIRES; and Wisconsin Electric Power Company.

necessary. For example, AEP, joined by Integrys, contends that utility and regional transmission planning efforts have a limited geographic perspective and do not consider the benefits associated with interregional transmission projects in neighboring regions. Boundless Energy and Sea Breeze state that in the absence of RTOs and ISOs, and particularly in WECC, interregional transmission planning is ineffective, overly costly, and focuses on individual transmission projects with no relationship to the grid as a whole network or a smart grid.

352. Other commenters argue that there is no coordinated process between regions with respect to evaluating interregional transmission projects.[320] AEP and MidAmerican specify that the lack of a coordinated process between transmission planning regions creates hurdles for projects (especially proposed extra high voltage facilities) that are unreasonably higher than those faced by intraregional transmission projects. MidAmerican contends that different regions have different planning protocols and rules for project evaluation and justification, and focus too narrowly on planning criteria that are limited to reliability, generator interconnection, and economic congestion relief to demonstrate the need for a project. It states that many transmission planning regions do not have joint planning protocols or other tariff authority under which an interregional project could be approved based on the total benefits that it provides to the planning regions; and that there is a lack of coordinated planning to identify the most economically efficient solutions. Transmission Dependent Utility Systems state that the ultimate objective of the Final Rule should be the development of a regional transmission plan that jointly optimizes solutions for transmission across the regions to allow access to economically-priced energy by all transmission providers and customers to best serve their native loads. 26 Public Interest Organizations state that without interregional coordination of planning assumptions and procedures, it may not be possible to develop regional transmission plans that the Commission can rely on to determine whether rates are just and reasonable.

353. Some other commenters state that improved interregional transmission coordination would result in a more orderly and timely transmission planning process.[321] Pioneer Transmission indicates that improved interregional transmission planning would require planning regions to adopt broader planning goals and objectives, plan transmission and generation in a coordinated and cohesive fashion, and recognize that the benefits of interregional transmission projects will multiply and that their beneficiaries often expand over time.

354. Several commenters also discuss the positive impacts that the proposed interregional transmission planning requirements would have on renewable resources. For example, some state that these requirements would facilitate access to renewable energy and help meet state, federal and other renewable energy goals.[322] Pattern Transmission indicates that unless a formal interregional planning process is required, approval of transmission projects needed to allow load to access renewable resources will be difficult, particularly for remotely-located resources. Wind Coalition states that without interregional planning, location-constrained resources located in one region that could be cost-effectively accessed to serve the needs of an adjacent, or even more distant region, will not be available or may be accessed through a more expensive and less efficient transmission solution than would be possible with interregional transmission planning.

355. Some commenters argue that seams issues have prevented efficient use of existing transmission infrastructure and adequate consideration of the needs of load-serving entities at the seams.[323] Several commenters cite difficulties they have had in the MISO and PJM, Entergy and SPP, PJM and New York ISO, and Pacific Northwest regions.[324] For example, East Texas Cooperatives state a lack of coordination between SPP and Entergy has hindered its ability to obtain network service for a new generating plant. Specifically, East Texas Cooperatives state that in 2009 they submitted a request to SPP for 335 MW of network service sourcing and sinking in SPP to access the Harrison County generating plant. When studying the request, SPP determined that it may cause impacts on Entergy's system. After multiple iterations of the SPP Aggregate Study Process and two Affected System Analysis were conducted, the Entergy system identified $30.7 million of upgrades necessary to facilitate the request, the cost of which were to be directly assigned to East Texas Cooperatives. East Texas Cooperatives identified several potential issues in the SPP and Entergy studies that appeared to stem, at least in part, from a lack of queue coordination between Entergy and SPP. East Texas Cooperatives state that after significant effort on their part and additional study costs being incurred, which may not have been necessary with better coordination between Entergy and SPP, the cost of the necessary upgrades on the Entergy system was dramatically reduced. However, East Texas Cooperatives state that errors in SPP's planning studies and a lack of coordination between SPP and Entergy in addressing East Texas Cooperatives' network service request, resulted in a long delay in securing the necessary financing for the Harrison County project.

356. Similarly, ITC Companies state that it has been difficult to move forward on its Green Power Express project because there is no applicable planning process for projects that extend beyond the boundaries of a single RTO. Exelon states that its experience on the seam between MISO and PJM supports the contention that mandatory interregional planning is needed at this time. For instance, Exelon cites issues in studying and building transmission projects identified in the MISO's Regional Generation Outlet Study as necessary to deliver 35 GW of wind energy to load centers in the MISO. Exelon states that several of the projects are located in PJM, but will not be studied further by the MISO because MISO states that it has no authority to order its members or PJM members to build transmission on PJM's system. In addition, Exelon states that current coordination protocols between the MISO and PJM are failing to prevent increased congestion in PJM, resulting in deteriorating operations at the seam such as increased transmission loading relief (TLR) events on the Commonwealth Edison system. PJM, however, disputes Exelon's assertions regarding both the cause and the total number of TLR events on the Commonwealth Edison system.

357. PSEG Companies recommend that where there is evidence of

[320] *E.g.,* East Texas Cooperatives; AEP; Kansas City Power & Light and KCP&L Greater Missouri; Anbaric and PowerBridge; Edison Electric Institute; MISO Transmission Owners; TDU Systems; AWEA; and PSEG Companies.

[321] *E.g.,* First Wind; Solar Energy Industries; and Large-scale Solar.

[322] *E.g.,* Edison Electric Institute; AWEA; Clean Line; American Transmission; and Solar Energy Industries and Large-scale Solar.

[323] *E.g.,* AEP; Anbaric and PowerBridge; Connecticut & Rhode Island Commissions; East Texas Cooperatives; Edison Electric Institute; Energy Consulting Group; MISO Transmission Owners; Northeast Utilities; and Omaha Public Power District.

[324] *E.g.,* Pennsylvania PUC; MidAmerican; Exelon; East Texas Cooperatives; PSEG Companies; and Powerex.

significant seams issues that affect operations, the Commission should require that the affected planning regions: (1) coordinate the planning of their systems, including sharing information needed to forecast, measure, and monitor impacts; and (2) form an agreement to address how the costs associated with cross-border impacts will be allocated that incorporates the ''beneficiary pays'' approach. Pennsylvania PUC states that the Commission's proposed interregional transmission planning requirements may help to improve interregional operational efficiency between RTOs.

358. Organization of MISO States and Pattern Transmission discuss the effect of improved interregional coordination between RTO and non-RTO regions. Organization of MISO States notes that the proposed requirements would enhance the incorporation of non-RTO regions into interregional transmission planning processes. According to Pattern Transmission, interregional transmission planning is particularly important in non-RTO and non-ISO regions, where the lack of a structured regional transmission planning process effectively restricts transmission development by nonincumbent developers to merchant transmission developers.

359. Transmission Dependent Utility Systems urge the Commission to adopt the proposed interregional transmission planning reforms without delay as they are necessary to promote cost-effective interregional transmission planning and to remedy the unduly discriminatory exclusion of transmission customers that are load-serving entities from these activities. They assert that transmission providers have little incentive to develop transmission that would allow competing suppliers to serve customers and that in many regions, interregional transmission planning efforts are either nonexistent or are often implemented through bilateral agreements that provide no opportunity for active participation by transmission customers that are load-serving entities or other stakeholders.

360. Several commenters stress that the Commission's actions in this proceeding must not interfere with the ARRA-funded transmission planning initiatives.[325] Allegheny Energy Companies believe in the potential success of the ARRA-funded process. They state that the ARRA-funded interconnectionwide transmission planning initiatives may develop into a potential model for an open, interconnectionwide transmission planning process and in effect could help resolve some of the planning issues currently being encountered. Western Area Power Administration urges the Commission to consider the positive developments associated with the implementation of these initiatives while developing any Final Rule.

361. Some commenters argue that interregional transmission planning reforms are needed notwithstanding the ARRA-funded interconnectionwide transmission planning initiatives.[326] SPP states that the ARRA-funded process will not ensure that the most cost-effective solutions are implemented across planning regions or the entire interconnection. Transmission Dependent Utility Systems also contend that the ARRA-funded process does not address short-range needs for interregional projects and may have too wide of a geographic scope to conduct the bottom-up planning necessary to ensure that the needs of load-serving entities are met. AEP encourages the Commission to provide as much direction as possible to the planning authorities to ensure that the ARRA initiatives accomplish more than the cumulative assembly of the isolated plans of each region and planning entity.

362. Conversely, other commenters suggest that the Commission postpone imposing new requirements until after the ARRA-funded interconnection-wide transmission planning process is complete.[327] For example, Southwest Area Transmission Sub-Regional Planning Group encourages the Commission to support existing planning activities, postponing the proposal for additional requirements until after the ARRA-funded interconnectionwide transmission planning initiatives are complete. ColumbiaGrid and ISO New England argue that their transmission planning processes already comply with the Commission's proposed requirements. The New England Transmission Owners support the Commission's interregional transmission planning objectives, but urge the Commission to give the ISO New England's existing interregional transmission planning process time to mature before imposing any new or additional requirements. PHI Companies argue that the Commission should require that existing interregional planning processes that meet the Commission's articulated principles be followed whenever the objectives of one region have the potential to impose burdens or costs on another region.

363. Other commenters oppose the Commission's proposed interregional transmission planning requirements, arguing they are unnecessary[328] or premature.[329] In particular, several commenters state that existing transmission planning processes in their regions (West, Southeast, Midwest) have led to significant progress and that there is no need for mandating that regions create interregional transmission planning agreements.[330] For example, Southern Companies state that there already is an institution in place to provide interregional coordination in the Eastern Interconnection, namely the Eastern Interconnection Planning Collaborative. Salt River Project similarly states that it participates in robust and effective planning activities in the West, and provides an inventory of projects, including interregional lines that are being built as a result of coordination between regional and subregional planning groups. Southern Companies note that the Commission's proposed interregional transmission planning requirements are unnecessary as the deficiencies alleged by the Commission in the Proposed Rule are not applicable in the Southeast. Organization of MISO States expresses its view that the Commission should give the interconnectionwide Eastern Interconnection States Planning Council planning process some time to work before requiring the filing of any bi-regional interregional transmission planning agreements.

364. Salt River Project and Southwest Area Transmission contend that the proposed requirements are premature because the Commission did not provide specific examples of deficiencies and lack of coordination in the transmission planning process that support the need for the proposed requirements. They recommend that the Commission undertake a comprehensive

[325] *E.g.,* Indianapolis Power & Light; NARUC; PHI Companies; Pennsylvania PUC; PSC of Wisconsin; SPP; and Transmission Access Policy Study Group.

[326] *E.g.,* SPP; Minnesota PUC and Minnesota Office of Energy Security; AEP; and Transmission Dependent Utility Systems.

[327] *E.g.,* Southwest Area Transmission Sub-Regional Planning Group; APPA; and Xcel.

[328] *E.g.,* California ISO; ColumbiaGrid; Indianapolis Power & Light; National Rural Electric Coops; Southern Companies; and Washington Utilities and Transportation Commission.

[329] *E.g.,* Georgia Transmission Corporation; Salt River Project; and Southwest Area Transmission Sub-Regional Planning Group.

[330] *E.g.,* Salt River Project; Southwest Area Transmission Sub-Regional Planning Group; Xcel; California Commissions; San Diego Gas & Electric; NEPOOL; Northeast Utilities; New England Transmission Owners; Southern Companies; Washington Utilities and Transportation Commission; and Indianapolis Power & Light.

and thorough inventory of existing planning processes and then use the demonstrable outcomes of these processes to identify any real barriers that would merit new rules or regulations. National Rural Electric Coops, Indianapolis Power and Light, and Transmission Agency of Northern California contend, in whole or part, that the Commission should pursue only additional reforms that address specific problems identified in the record from this proceeding, that mandatory coordination should occur on an as-needed basis where such efforts are likely to lead to substantial transmission development, and that any further reforms be targeted to specific problems.

365. Some commenters suggest that the Commission should allow Order No. 890 processes to develop further before imposing new interregional coordination requirements.[331] Xcel acknowledges the need for interregional planning and cost allocation mechanisms to support public policy mandates, but recommends that the Commission allow current voluntary interregional planning and cost allocation discussions to continue, rather than mandate the development of interregional agreements within a specified time frame.

366. Similarly, several commenters contend that interregional coordination should be voluntary. Ad Hoc Coalition of Southeastern Utilities and Bonneville Power contend that the Commission should permit parties to pursue voluntary interregional transmission planning agreements. Ad Hoc Coalition of Southeastern Utilities states that it supports voluntary efforts of regional transmission processes to address facilities located in multiple regions. Similarly, North Carolina Agencies state that coordination among regions, as well as within a broadly defined region, should be voluntary. Bonneville Power states that the Commission has not demonstrated that the voluntary approach does not work in the Pacific Northwest or that it is not just and reasonable or that it is unduly discriminatory or preferential. It recommends that if the Commission mandates interregional transmission planning agreements, it should permit parties the discretion to pursue voluntary agreements for interregional planning in general, as well as for specific projects. Further, California ISO points to successful voluntary coordination efforts in the West by WECC and California Transmission Planning Group. California PUC, in its reply comments, supports California ISO's and Bonneville Power's views.

367. Other reply commenters disagree with these arguments. 26 Public Interest Organizations respond that the Commission is obligated under the FPA to ensure that changing system needs (such as state renewable portfolio standards and new federal environmental rules) and the consequences for systems outside of the RTO's footprint (such as loop flow) are justly and reasonably addressed, which requires interregional coordination. WIRES replies that interregional planning must be made mandatory and subject to stronger Commission oversight and participation. WIRES states that experience demonstrates that, left to the voluntary cooperation of the parties, the transmission network will not be integrated as effectively as it could be, reliability and resource diversity will suffer, and seams and congestion issues will be unresolved.

c. Commission Determination

368. The Commission concludes that implementation of further reforms in the area of interregional transmission coordination activities are necessary at this time. As the Commission stated in the Proposed Rule, in the absence of coordination between transmission planning regions, public utility transmission providers may be unable to identify more efficient or cost-effective solutions to the individual needs identified in their respective local and regional transmission planning processes, potentially including interregional transmission facilities. Clear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans.

369. Specifically, we agree with commenters, such as AEP, that the transmission planning requirements of Order No. 890 are too narrowly focused geographically and fail to provide for adequate analysis of the benefits associated with interregional transmission facilities in neighboring transmission planning regions. Our decision also is influenced by those commenters that cite seams issues or difficulties they have encountered in coordinating the development of transmission facilities across the regions, including between RTOs and ISOs, as well as between an RTO or ISO and non-RTO or ISO region and among non-RTO regions. We are persuaded by those commenters who argue that additional interregional transmission coordination requirements would facilitate consideration of transmission needs driven by Public Policy Requirements by enabling the evaluation of interregional transmission facilities that may address those needs more efficiently or cost-effectively. We agree with Transmission Dependent Utility Systems' comments that interregional transmission coordination promotes cost-effective transmission development and facilitates transmission customer participation in interregional transmission coordination efforts.

370. Given the clear need for reform of existing interregional transmission coordination practices, we are not persuaded by arguments contending that reform is not necessary or is premature. While we recognize that significant progress with respect to the development of open and transparent transmission planning processes has been made around the country, the existing transmission planning processes nevertheless do not adequately provide for the evaluation of proposed interregional transmission facilities or the identification of interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. Because such interregional transmission coordination helps to ensure that rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential by facilitating more efficient or cost-effective transmission infrastructure development, we conclude that the interregional transmission coordination reforms adopted in this Final Rule are necessary and should not be delayed.

371. Similarly, while we have considered the positive developments associated with the ARRA-funded transmission planning initiatives, we nevertheless agree with commenters who argue that the Commission should not postpone its proposed interregional transmission coordination reforms on account of these initiatives. While the ARRA-funded transmission planning initiatives represent a significant advancement in interconnectionwide transmission scenario analysis, they do not specifically provide for the ongoing coordination in the evaluation of interregional transmission facilities, which we conclude is necessary to ensure that rates, terms, and conditions of jurisdictional services are just and

[331] *E.g.*, Washington Utilities and Transportation Commission; Georgia Transmission Corporation; and Xcel.

reasonable and not unduly discriminatory or preferential. As requested by commenters, however, we have extended the compliance deadline for the interregional coordination requirements of this Final Rule, as discussed in section V.A below. We encourage public utility transmission providers to continue their participation in these efforts and to explore opportunities to use the valuable information these efforts provide in their regional transmission planning and interregional transmission coordination efforts. We reiterate our intent to build upon, and not interfere with, the ARRA-funded transmission planning initiatives in this Final Rule.

372. With regard to commenters' contentions that their existing interregional transmission coordination efforts already comply with the Proposed Rule's provisions or need more time to mature, we acknowledge that some transmission planning regions already may engage in interregional transmission coordination efforts that satisfy some of the requirements discussed below or are developing such efforts. The Commission is acting in this Final Rule to establish a minimum set of requirements that apply to all public utility transmission providers. If a public utility transmission provider believes that it participates in a regional transmission planning process that fulfills the interregional transmission coordination requirements adopted in this Final Rule, it may describe in its compliance filing how such participation complies with the requirements of this Final Rule.

373. We therefore disagree that the Commission should undertake additional investigation of the need for interregional coordination procedures or require them only on a case-by-case basis. The record in this proceeding is adequate to support our conclusion that the existing requirements of Order No. 890 are too narrowly focused geographically. Coordination of transmission planning activities by neighboring transmission planning regions will increase opportunities to identify interregional transmission facilities that address the needs of those regions more efficiently or cost-effectively. We thus see no need to adopt a case-by-case approach to our requirements. We conclude that the interregional coordination obligations implemented in this Final Rule are necessary to establish a minimum set of requirements that are applicable to all public utility transmission providers.

2. Interregional Transmission Coordination Requirements

a. Interregional Transmission Coordination Procedures

i. Commission Proposal

374. In the Proposed Rule, the Commission proposed to require each public utility transmission provider through its regional transmission planning process to enter into agreements that include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed that could address transmission needs more efficiently than separate intraregional facilities.[332] While acknowledging that every transmission planning agreement could be tailored to best fit the needs of the transmission planning regions entering into the agreement, the Commission proposed that each public utility transmission provider ensure that certain elements are included in each agreement.

375. Specifically, the Commission proposed that an interregional transmission planning agreement must include the following elements: (1) A commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities (Coordination); (2) an agreement to exchange at least annually planning data and information (Data Exchange); (3) a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions (Joint Evaluation); and (4) a commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated transmission planning process (Transparency).

376. With respect to the third proposed element, the Commission proposed that the transmission developer of a transmission project that would be located in two neighboring transmission planning regions must first propose its transmission project in the transmission planning process of each of those transmission planning regions. The Commission further proposed that such a submission would trigger a procedure established by the interregional transmission planning agreement, under which the transmission planning regions would coordinate their reviews of and jointly evaluate the proposed transmission project. The Commission proposed that such coordination and joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project. Finally, the Commission proposed that inclusion of the interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to application of an interregional cost allocation method that satisfies the cost allocation principles set forth in the Proposed Rule.

ii. Comments

377. American Transmission supports requiring regions to make a commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently than separate intraregional facilities. However, American Transmission also recommends that the Commission require public utility transmission providers to specifically describe the process by which their planning regions will identify such interregional transmission facilities. East Texas Cooperatives suggest that the Commission clarify that it requires more than simple coordination (*i.e.*, the sharing of information and plans), but also the establishment of an interregional transmission planning process intended to address and resolve seams issues.

378. Several commenters request that the Commission provide more detailed guidance on the interregional transmission planning agreements.[333] MISO Transmission Owners similarly request that the Commission clarify its specific expectations for interregional coordination. SPP recommends that the Final Rule provide detailed guidance concerning the requirements for interregional transmission planning, including the goals and objectives of interregional transmission planning. Powerex states that the Commission should require each interregional transmission planning agreement to include a set of interregional planning goals that are concrete and outcome-

[332] The Commission discusses in subsection 3e below comments in response to the proposal for interregional transmission coordination activities to be memorialized in an agreement executed by multiple public utility transmission providers.

[333] *E.g.*, 26 Public Interest Organizations; MISO Transmission Owners; SPP; and Sunflower and Mid-Kansas.

based and that directly address the reliability problems that reduce efficiency. ITC Companies state that interregional transmission planning agreements should include the key criteria to be considered in the interregional planning process, based on the planning principles, and the cost allocation method that would apply to approved interregional projects.[334]

379. Old Dominion recommends that the Commission require public utility transmission providers and interregional planning entities, such as the Eastern Interconnection Planning Collaborative, to adopt transmission planning processes that: (1) Identify the needs of multiple transmission systems based on scenario planning using a long-term planning horizon (*e.g.*, 15 to 20 years); (2) conduct various scenario analyses to identify the projects that best address reliability, economic, or demand response concerns; and (3) allow developers to compete to provide the ''best'' solution.

380. Some commenters support a more robust interregional transmission planning process than the interregional coordination requirements set forth in the Proposed Rule. For example, Energy Future Coalition states the interregional transmission planning process should include a rigorous and transparent analysis of a comprehensive set of considerations and alternatives and provide for ''right-sizing'' facilities to ensure the best possible use of existing corridors and minimize environmental impacts from new corridors.

381. A few commenters recommend that the Commission require interregional transmission planning processes to comply with the Order No. 890 planning principles.[335] Transmission Dependent Utility Systems contend that subjecting interregional transmission planning processes to the Order No. 890 planning principles would alleviate concerns about the limited size of some Order No. 890-compliant planning regions, which arose due to the lack of an opportunity for load-serving entities to participate in planning across seams, and would ensure that the most cost-effective solutions to constraints associated with seams are pursued. Old Dominion states that requiring interregional transmission planning processes to comply with the Order No. 890 planning principles would ensure that information will flow between the regional and interregional transmission planning processes, so that stakeholders will have the information necessary to offer meaningful input at the interregional level and to inform discussions at the regional levels.

382. Energy Consulting Group states that transmission owners should be required to develop the transmission upgrades and expansions identified in the wide-area planning process within a mandated time frame. NextEra states that the Commission should require the interregional transmission planning process to result in an interregional transmission plan that includes interregional transmission facilities identified through the planning process. Boundless Energy and Sea Breeze contend that the Commission should strengthen interregional transmission planning processes by requiring implementation of interregional transmission plans and an implementing authority. MidAmerican expresses concern that proposed element 1 does not describe how the Commission intends neighboring planning regions to move those interregional projects identified towards construction, and recommends that the Commission require the identified interregional facilities to be included in local and regional transmission plans. Similarly, National Grid recommends that the Commission require consideration of procedures for adopting into regional plans any transmission upgrade identified as part of an interregional coordination process.

383. Southwest Area Transmission Sub-Regional Planning Group, however, states that the Commission should clarify that interconnectionwide, regional, and interregional planning groups are not decision-making entities with the authority to direct developers or load-serving entities to develop any project. National Grid asks the Commission not to require the formation of new interregional planning entities, especially where interregional planning efforts are already underway.

384. NextEra also states that the Commission should require the interregional transmission planning process to result in an interregional transmission plan that includes longer-term objectives that have not yet resulted in proposals for specific facilities. Similarly, California Commissions state that plans should contain conceptual elements that have yet to materialize as specific transmission projects and contingent elements that may be needed under certain future scenarios so that a plan can evolve over time.

385. Solar Energy Industries and Large-scale Solar and Anbaric and PowerBridge urge the Commission to impose stronger requirements for interregional coordination for public policy and renewable energy projects. MidAmerican asks that the Commission clarify that consideration of public policy requirements is not limited to local and regional transmission planning processes but should be extended to interregional transmission coordination as well.

386. On the other hand, Energy Consulting Group contends that interregional transmission planning should provide an incentive for development of transmission facilities that provide access to economic generation resources that minimize power costs, not act as an instrument of public policy. Energy Consulting Group also states that it is not clear that the proposed transmission planning processes will have a mechanism to address transmission service requests, and that a process for addressing such requests should be added to wide-area planning.

387. ITC Companies contend that interregional coordination should assure equal consideration for all drivers of transmission needs, including reliability, generator interconnection, and public policy requirements. National Grid requests that the Commission require interregional transmission planning efforts to consider transmission upgrades that could provide economic benefits to consumers in multiple regions and upgrades or modified operating practices that could result in more efficient use of the existing transmission system in addition to those transmission facilities needed to maintain reliability. Powerex states that the Final Rule should establish policies that encourage transmission customers to continue to purchase and invest in long-term transmission and that the Commission should ensure that it is sending proper signals for long-term investments in transmission by rejecting policies that erode the existing rights of firm transmission customers that have already made long-term investments in transmission service.

388. Organization of MISO States urges the Commission to encourage transmission planning regions to coordinate on issues besides transmission planning and cost allocation, such as interconnection and operational issues.

389. North Carolina Agencies state that coordination among regions, as well as within a broadly defined region, should complement, rather than

[334] The cost allocation method that would apply to selected interregional transmission facilities is addressed in the cost allocation section below. *See* discussion *supra* section IV.E. of this Final Rule.

[335] *E.g.,* East Texas Cooperatives; ITC Companies; Old Dominion; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

substitute for, local and narrower regional planning processes. NEPOOL and Northeast Utilities state that the Proposed Rule's provisions, which reflect a ''bottom up'' planning approach, should be reflected in any Final Rule. Other commenters also support a ''bottom up'' approach to interregional transmission planning.[336]

390. Other commenters urge the Commission to ensure that the Final Rule does not infringe on state authority. California Commissions emphasize that rules pertaining to interregional transmission planning agreements and the resulting coordinated planning process must not diminish state control by shifting decision-making to the Commission and that states should be directly involved in the development of interregional transmission planning agreements and should have a strong role in their implementation. NARUC asserts that the interregional transmission planning process must continue to respect the role of state commissions in reviewing and guiding the planning process and the role of state authorities in ultimately siting any transmission lines.

391. Several commenters request that the Commission oversee the development and implementation of interregional transmission planning agreements and/or monitor the progress of interregional planning efforts.[337] For example, Organization of MISO States suggests that the Commission require an accountability and oversight element in interregional transmission planning agreements to ensure that such agreements are implemented as intended, perhaps utilizing the expertise of state commissions. American Transmission and MISO Transmission Owners state that public utility transmission providers and their stakeholders should be required to conduct periodic reviews of the effectiveness of their interregional transmission planning efforts and file informational reports with the Commission.

392. Federal Trade Commission acknowledges that the Commission's proposed interregional transmission planning requirements would require market participants that may be competitors to collaborate with each other in transmission planning, construction, ownership, and operation, but states that participants in the interregional transmission planning process should not view the antitrust laws as an impediment to their participation.

iii. Commission Determination

393. To remedy the potential for unjust and unreasonable rates for public utility transmission providers' customers, we adopt the interregional transmission coordination requirements discussed below. These interregional transmission coordination requirements obligate public utility transmission providers to identify and jointly evaluate interregional transmission facilities that may more efficiently or cost-effectively address the individual needs identified in their respective local and regional transmission planning processes.

394. In the Proposed Rule, the Commission set forth its proposed interregional transmission coordination requirements in the form of four elements to be included in an interregional transmission planning agreement. After reviewing the comments concerning interregional transmission coordination received in this proceeding, we find that these four elements are so extensively interconnected that it would be inappropriate to require that they be addressed as distinct elements, as was proposed in the Proposed Rule. Instead, we believe that these four elements are better represented as characteristics of interregional transmission coordination. Specifically, two of the proposed elements—Coordination and Joint Evaluation—embody the purpose of interregional transmission coordination: to coordinate and share the results of regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities and to jointly evaluate such facilities, as well as to jointly evaluate those transmission facilities that are proposed to be located in more than one transmission planning region. The other two elements—Data Exchange and Transparency—are more appropriately described as part of the procedures through which effective interregional transmission coordination is implemented.

395. Thus, the framework in which we present these requirements differs from that of the Proposed Rule. This Final Rule lays out the objectives of interregional transmission coordination followed by a discussion of the mechanics of interregional transmission coordination instead of four required elements. Here we address the requirements for interregional transmission coordination, the entities between which interregional transmission coordination must occur, and the transmission facilities to which the interregional transmission coordination requirements apply. Hence the discussion of Coordination and Joint Evaluation is here. We address in other sections below the mechanics of implementation, including a discussion of the procedures for joint evaluation, requirements for data exchange, transparency, stakeholder participation, and the required revisions to the OATT.

396. The Commission requires each public utility transmission provider, through its regional transmission planning process, to establish further procedures with each of its neighboring transmission planning regions for the purpose of coordinating and sharing the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. Through adoption of this requirement, the Commission intends that neighboring transmission planning regions will enhance their existing regional transmission planning processes to provide for: (1) The sharing of information regarding the respective needs of each region, and potential solutions to those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs.[338] By requiring public utility transmission providers to undertake such interregional transmission coordination activities, the Commission and transmission customers will have greater certainty that the transmission facilities in each regional transmission plan are more efficient or cost-effective solutions to meeting transmission planning region's needs.

397. In response to the Proposed Rule, several commenters seek clarification from the Commission as to whether, for example, the Commission intends the formation of a new interregional transmission planning process or that certain types of facilities or objectives should be the focus of interregional transmission coordination. With the exception of the requirements for

[336] *E.g.*, Allegheny Energy Companies; East Texas Cooperatives; and ISO New England.

[337] *E.g.*, Energy Future Coalition; Organization of MISO States; Transmission Dependent Utility Systems; and AWEA.

[338] The same language must be included in each public utility transmission provider's OATT that describes the processes that a particular pair of transmission planning regions will use to satisfy the interregional transmission coordination requirements of this Final Rule. The filing requirements concerning this same language are discussed in the compliance section below. *See* discussion *infra* section VI.A. of this Final Rule.

implementing interregional transmission coordination discussed herein, the Commission declines at this time to impose specific obligations as to how neighboring transmission planning regions must share information regarding their needs, and potential solutions to those needs, or identify and jointly evaluate interregional transmission alternatives to those regional needs, as well as proposed interregional transmission facilities. Thus, we also decline to require the use of specific planning horizons or the performance of particular scenario analyses. While we appreciate commenters' desire for additional clarity on this point, the Commission believes it is appropriate to leave to the transmission planning regions in the first instance adequate discretion to allow for the development and implementation of interregional transmission coordination procedures that suit the needs of the neighboring transmission planning regions. In light of the varying approaches to transmission planning that are currently used by transmission planning regions across the country, providing further guidance at this time could inadvertently impose restrictions that are not appropriate for a particular transmission planning region.

398. However, we clarify in response to East Texas Cooperatives that the interregional transmission coordination requirements adopted do require that public utility transmission providers do more than simply commit to share their regional transmission plans and other transmission planning information. To comply with the requirements in this Final Rule, each public utility transmission provider, through its regional transmission planning process, must develop and implement additional procedures that provide for the sharing of information regarding the respective needs of each neighboring transmission planning region, and potential solutions to those needs, as well as the identification and joint evaluation of interregional transmission alternatives to those regional needs by the neighboring transmission planning regions. On compliance, public utility transmission providers must describe the methods by which they will identify and evaluate interregional transmission facilities. While the Commission does not require any particular type of studies to be conducted, this Final Rule requires public utility transmission providers in neighboring transmission planning regions to jointly identify and evaluate whether interregional transmission facilities are more efficient or cost-effective than regional transmission facilities. Accordingly, the Commission requires that the compliance filing by public utility transmission providers in neighboring planning regions include a description of the type of transmission studies that will be conducted to evaluate conditions on their neighboring systems for the purpose of determining whether interregional transmission facilities are more efficient or cost-effective than regional facilities.

399. We decline to adopt the recommendations of those commenters that suggest that the Commission adopt a more robust, formalized interregional transmission planning process than the interregional transmission coordination requirements in the Proposed Rule, such as an interregional transmission coordination process that complies with the Order No. 890 transmission planning principles or that produces an interregional transmission plan. We clarify here that the interregional transmission coordination requirements that we adopt do not require formation of interregional transmission planning entities or creation of a distinct interregional transmission planning process to produce an interregional transmission plan. Rather, our requirement is for public utility transmission providers to consider whether the local and regional transmission planning processes result in transmission plans that meet local and regional transmission needs more efficiently and cost-effectively, after considering opportunities for collaborating with public utility transmission providers in neighboring transmission planning regions. To the extent that public utility transmission providers wish to participate in processes that lead to the development of interregional transmission plans, they may do so and, as relevant, rely on such processes to comply with the requirements of this Final Rule.

400. While we acknowledge MidAmerican's concern that the Commission does not specify how interregional transmission facilities will be moved toward construction, we note that in the Proposed Rule, the Commission stated that, consistent with Order No. 890, the proposed regional transmission planning obligations do not address or dictate which investments identified in a transmission plan should be undertaken by public utility transmission providers.[339] We affirm that statement, and further note that Order No. 890 already requires that public utility transmission providers make available information regarding the status of transmission upgrades identified in their regional transmission plans in addition to the underlying transmission plans and related transmission studies.[340] The Commission made clear in Order No. 890–A that transmission providers must make available to other stakeholders information regarding the progress and construction of transmission upgrades and transmission facilities.[341] To the extent neighboring transmission planning regions identify interregional transmission facilities of mutual benefit and have such transmission facilities in their individual regional transmission plans, these informational requirements will apply to the portions of the interregional transmission facilities within each of the individual region's transmission plans. We decline to require, as suggested by MidAmerican and National Grid, that every interregional transmission facility that is evaluated through the interregional transmission coordination procedures automatically be selected in a regional transmission plan for purposes of cost allocation. However, as discussed below, an interregional transmission facility must be selected in both of the relevant regional transmission plans for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to an interregional cost allocation method required under this Final Rule. Rather, we expect that information exchanged during the interregional coordination effort should inform discussions at the regional and local transmission planning level.

401. Moreover, in response to commenters, this Final Rule neither requires nor precludes longer-term interregional transmission planning, including the identification of conceptual or contingent elements,[342] the consideration of transmission needs driven by Public Policy Requirements,[343] or the evaluation of economic considerations.[344] Whether and how to address these issues with regard to interregional transmission facilities is a matter for public utility transmission providers, through their regional transmission planning processes, to resolve in the development of compliance proposals. However, the

[339] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.59 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438).

[340] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472.

[341] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 202.

[342] *See* California Commission.

[343] *See* MidAmerican.

[344] *See* Energy Consulting Group.

Commission agrees with North Carolina Agencies that interregional transmission coordination should complement local and regional transmission planning processes, and should not substitute for these processes. Consistent with the implementation requirements for interregional transmission coordination procedures discussed in section III.C.3.a. below, we clarify that interregional transmission coordination may follow a ''bottom up'' approach. In response to Energy Consulting Group, we neither require nor prohibit consideration by neighboring transmission planning regions of requests for transmission service or upgrades within the interregional transmission coordination procedures required in this Final Rule.

402. With respect to commenters' assertion that this Final Rule should not infringe on state authority, we emphasize here that the interregional transmission coordination requirements are not intended to infringe on state authority. We acknowledge the vital role that state agencies play in transmission planning and their authority to site transmission facilities. We strongly encourage state agencies to be involved in the development and implementation of the interregional transmission coordination procedures necessary to satisfy the interregional transmission coordination requirements adopted herein.

403. In response to commenters' requests that we monitor the implementation of the interregional transmission coordination requirements adopted in this Final Rule and the progress of interregional transmission coordination efforts, although the Commission believes that Commission oversight of compliance with this Final Rule and assessment of the adequacy of its measures is appropriate, the Commission does not intend to monitor coordination efforts so closely as to intrude in the interregional transmission coordination activities. It is not necessary for the Commission to decide the exact level of its monitoring at this time.

404. We also decline to require public utility transmission providers and their stakeholders to conduct periodic reviews of the effectiveness of their interregional transmission coordination efforts and file information reports with us, as suggested by American Transmission and MISO Transmission Owners. However, we do encourage such reviews. We also note that parties may utilize the dispute resolution provisions of the relevant public utility transmission provider's OATT or file a complaint with the Commission if they find that the interregional transmission coordination procedures described in a public utility transmission provider's OATT are not being implemented properly.

b. Geographic Scope of Interregional Transmission Coordination

i. Commission Proposal

405. As noted above, the Commission proposed to require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to address transmission planning issues. The Commission noted that this does not require a public utility transmission provider to coordinate with a neighboring transmission planning region in another interconnection. However, the Commission also encouraged public utility transmission providers to explore possible multilateral interregional transmission coordination processes among several, or even all, transmission planning regions within an interconnection, building on processes developed through the ARRA-funded transmission planning initiatives.[345] The Commission proposed to require interregional coordination between public utility transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed but that could address transmission needs more efficiently than separate intraregional transmission facilities.[346]

ii. Comments

406. The Commission received a number of comments addressing the geographic scope of the proposed interregional coordination requirements, as well as the specific entities within the appropriate geographic scope that would be required to coordinate. Several commenters suggest that the Commission clarify how it defines regions for purposes of regional transmission planning to provide clarity as to how its proposed interregional transmission planning requirements will be implemented.[347] Transmission Dependent Utility Systems recommend that the Commission define regional boundaries if it appears that there is discrimination or inefficiencies in the planning process. Others urge the Commission not to change existing areas over which transmission planning is now coordinated among transmission planning regions.[348] For example, Integrys suggests that the Final Rule should preserve the existing mandate that PJM and the MISO constitute a single common market in the application of interregional transmission planning rules, and thus should be considered, at least for certain purposes, a single region subject to the interregional transmission planning and cost allocation rules.

407. New York Transmission Owners agree with the Commission's proposal to require that interregional transmission planning agreements between neighboring planning regions address transmission facilities that are proposed to be located in both regions. However, New York ISO states that this requirement should not preclude planning regions from considering other types of projects.

408. Several commenters either agree with the Commission's encouragement to extend interregional planning voluntarily beyond coordination between neighboring transmission planning regions so as to cover larger areas or an interconnection, or ask the Commission to require planning over such larger areas. ITC Companies state that, because some projects may involve more than two transmission planning regions, interregional planning also may need to involve more than two transmission planning regions. WECC suggests that because it already serves as a facilitator for interconnectionwide transmission planning and coordination in the Western Interconnection, it could provide a forum for facilitating multilateral transmission planning agreements. Federal Trade Commission recommends that the Commission institutionalize interconnectionwide transmission planning to incorporate relevant congestion, reliability, and environmental considerations and to reflect the geographic scope of power flows.

409. AWEA recommends that the Commission require public utility transmission providers to enter into multilateral, or even interconnectionwide, interregional transmission planning agreements. Similarly, Wind Coalition encourages the Commission to consider extending its proposed interregional transmission planning requirements beyond adjacent planning regions to provide a process

[345] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 114–15.

[346] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 116.

[347] *E.g.,* Integrys; Transmission Dependent Utility Systems; and MISO Transmission Owners.

[348] *E.g.,* Integrys and National Grid.

for accessing location-constrained resources located in more distant regions. Grasslands contends that the Commission should not limit its proposed interregional coordination requirements to neighboring transmission planning regions within the same interconnection. Without interregional transmission planning between the interconnections, Grasslands claims that transmission developers will not develop transmission facilities that will efficiently link the interconnections in the future.

410. Organization of MISO States cautions that, even with implementation of the proposed interregional transmission planning requirements, it may be difficult to require any non-RTO or non-ISO public utility transmission provider to act in the best interests of a geographic footprint beyond its own. Thus, it states that efforts such as the Eastern Interconnection States Planning Council, which would view projects over a geographic region larger than the RTO footprint, may be valuable.

411. Other commenters support the Commission's intent not to mandate interconnectionwide transmission planning,[349] offering among other things that mandating interconnectionwide planning would increase the difficulty of resolving local issues by making coordinated planning among transmission planning regions more complex and risk frustrating the ARRA-funded interconnectionwide transmission planning initiatives.

412. American Transmission and MISO Transmission Owners state that with respect to planning activities in regions without an RTO or ISO, the Commission should provide guidance as to which entities would be required to coordinate with each other. Integrys states that the Commission might implement its proposed interregional transmission planning requirements in non-RTO regions by requiring transmission providers in such regions to form planning consortia that could operate within a region and/or between two or more regions. Indianapolis Power & Light suggests that the Commission clarify whether transmission providers would be required to coordinate with each individual entity or one planning region to coordinate with another planning region.

413. New York ISO states that the Commission should clarify that public utility transmission providers that are unable to reach interregional transmission planning agreements with neighboring Canadian systems will not be deemed out of compliance with the Final Rule.

414. MISO Transmission Owners state that the agreements should enable a region impacted by a proposed project located in a neighboring region to review the neighboring region's plans, and that the transmission planning regions subject to the agreement should agree on what level of impact is material, as well as how disputes between the parties will be resolved. Edison Electric Institute and Exelon likewise state that the Commission should require that interregional transmission planning agreements address transmission facilities located in a single region that could have significant adverse impacts on the reliability of neighboring regions. Moreover, Exelon states that interregional transmission planning agreements should require that if a proposed project would result in any reliability violations or increased congestion on a neighboring system, these impacts must be mitigated before the project is approved.

iii. Commission Determination

415. We require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to implement the interregional transmission coordination requirements adopted in this Final Rule. This requirement is necessary to improve coordination of neighboring transmission planning regions' activities, facilitating the identification and joint evaluation of interregional transmission solutions that could meet local and regional transmission needs more efficiently or cost-effectively than separate regional transmission solutions alone.

416. The Commission declines to expand the interregional transmission coordination requirements adopted herein to require joint evaluation of the effects of a new transmission facility proposed to be located solely in a single transmission planning region. Although this Final Rule requires each regional transmission planning process to identify the consequences of a proposed new transmission facility in another transmission planning region as we explain below in the discussion of Cost Allocation Principle 4,[350] we do not require that be done interregionally. To do so could have the effect of mandating interconnectionwide transmission planning, given that transmission facilities located within one transmission planning region often have effects on multiple neighboring systems, which could trigger a chain of multilateral evaluation processes. However, we believe that the exchange of planning data and information between neighboring transmission planning regions consistent with the interregional transmission coordination requirements of the Final Rule will assist transmission planners in understanding and managing the effects of a transmission facility located in one region upon another neighboring region. Further, although we decline to impose a joint evaluation by more than one region of a facility located solely in one transmission planning region, nothing in this Final Rule precludes public utility transmission providers from developing and proposing interregional processes for that purpose.[351]

417. While the Commission declines to require multilateral or interconnectionwide coordination in this Final Rule, we continue to encourage public utility transmission providers to explore the possibility of multilateral interregional transmission coordination among several, or even all, transmission planning regions within an interconnection, building on the processes developed through the ARRA-funded transmission planning initiatives. The Commission agrees that imposing multilateral or interconnectionwide coordination requirements at this time could frustrate the progress being made in the ARRA-funded transmission planning initiatives. To the extent that stakeholders in those planning initiatives wish to continue these activities at the conclusion of the ARRA-funded transmission planning initiatives, we encourage them to explore how existing regional transmission planning processes and interregional transmission coordination procedures implemented under Order No. 890 and this Final Rule could be enhanced to provide for such transmission planning activities.

[349] *E.g.,* Indianapolis Power & Light; Transmission Access Policy Study Group; MISO Transmission Owners; New York ISO; and Organization of MISO States.

[350] *See* discussion *infra* section IV.E.5. of this Final Rule.

[351] Moreover, the absence of such a requirement in this Final Rule does not affect any obligations public utility transmission providers may otherwise have to assess the effects of new transmission facilities on other systems, including but not limited to any other requirement of the OATT for interconnection studies, any requirement under the NERC reliability standards, and the requirements of Good Utility Practice.

418. We decline to adopt Grasslands' recommendation that the Commission require interregional transmission coordination between transmission planning regions located in different interconnections. While we recognize that interregional transmission coordination between transmission planning regions in different interconnections could provide transmission planning benefits, such as increased power flows between interconnections, it may provide greater benefits for some pairs of neighboring transmission planning regions than for others due to geographical and operational limitations. Therefore, while we encourage public utility transmission providers to consider coordinating with neighboring transmission planning regions in different interconnections where it would be helpful, we do not find it appropriate to require such coordination in this Final Rule.

419. In response to American Transmission and MISO Transmission Owners' request for guidance regarding the entities that they are required to coordinate with in neighboring regions without an RTO or ISO, we reiterate that we require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection. Thus, interregional transmission coordination would occur between the public utility transmission providers in two neighboring transmission planning regions.

420. As discussed above in the regional transmission planning section,[352] the Commission declines to revisit how each transmission planning region defines itself, as requested by Integrys and Transmission Dependent Utility Systems. We also decline to adopt Integrys' suggestion that the Commission could implement its interregional transmission coordination requirements in non-RTO regions by requiring public utility transmission providers in such regions to form planning consortia. Public utility transmission providers are free to do so; however, we do not want to foreclose other approaches to meeting the interregional transmission coordination requirements in this Final Rule.

421. We clarify for New York ISO that a public utility transmission provider will not be deemed out of compliance with this Final Rule if it attempts to and is unable to develop interregional transmission coordination procedures with neighboring transmission systems in another country.

3. Implementation of the Interregional Transmission Coordination Requirements

a. Procedure for Joint Evaluation

i. Comments

422. Several commenters express support for the Commission's proposal to require the development of a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in neighboring transmission planning regions.[353] Some commenters seek clarification of this requirement. For example, Duke suggests that the Commission clarify whether it intends that only one joint interregional study will be performed for a proposed interregional project, regardless of the number of regions that are crossed, as multiple studies would result in an inefficient use of resources. ISO/RTO Council and PJM ask whether the Commission intends ''joint evaluation'' to mean coordination of stakeholder meetings and processes and/or the creation of a new set of planning criteria and a new planning cycle. In addition, PJM requests clarification as to whether the Commission intends ''joint evaluation'' to be conducted consistent with an interregional agreement such as the PJM/MISO Joint Operating Agreement.

423. Several commenters urge the Commission to provide flexibility in developing and implementing planning agreements.[354] They state that although the Commission proposed to require that interregional transmission planning agreements include the four elements of interregional coordination, the Commission also encouraged every interregional transmission planning agreement to be tailored to best fit the needs of the regions entering into the agreement. ISO New England urges the Commission to allow flexibility for regions to define in their interregional transmission planning agreements what it means to ''jointly evaluate'' interregional projects.

424. In setting out the details of interregional coordination, PUC of Nevada urges the Commission to consider the ongoing efforts in the Western Interconnection to address interregional coordination. WestConnect Planning Parties state that any requirement to execute an interregional transmission planning agreement should respect the various organizational structures of existing regional and interregional planning processes, as well as allow signature by all formal participants in the interregional planning process instead of requiring ''formation of a legal entity authorized to act on behalf of those participants.''

425. Other commenters offer specific suggestions as to the design and implementation of interregional coordination procedures. Minnesota PUC and Minnesota Office of Energy Security argue that, for the studies of an entire project to be meaningful and informative, all transmission planning entities studying a project should be required to coordinate their information and studies. Pioneer Transmission recommends that the Commission require planning regions to evaluate interregional projects through a single, coordinated process. It believes that if projects are studied under separate procedures by each planning region, interregional coordination would be unnecessarily delayed and more expensive than if the project was studied under a single set of procedures. However, Connecticut & Rhode Island Commissions contend that the Commission should require that proposed interregional projects be independently processed through each applicable regional planning process before they are eligible for joint evaluation through interregional coordination procedures.

426. Old Dominion similarly recommends that coordinated analysis of interregional transmission facilities be accomplished through preliminary evaluation within existing regional transmission planning processes, followed by an evaluation of the project on an interregional basis. If the identified transmission facility is determined to meet interregional needs, the relevant transmission planning regions would incorporate the project into their regional transmission planning processes and further assess its effects on regional needs. Old Dominion recommends that the Commission require this ''feedback loop'' so that local and regional transmission plans can be reconsidered once an interregional transmission plan has been developed. Similarly, New England States Committee on Electricity supports the Commission's proposed interregional coordination requirements provided that interregional projects will be identified and developed through the current approach that begins with and respects the regional transmission

[352] *See supra* section III.A.3 of this Final Rule.

[353] *E.g.,* American Transmission; New York Transmission Owners; Northeast Utilities; and Transmission Dependent Utility Systems.

[354] *E.g.,* PUC of Nevada; New York ISO; and Dayton Power and Light.

planning process and resulting regional transmission plan.

427. Several commenters suggest that the Commission should develop a *pro forma* interregional transmission planning agreement. NextEra suggests that such an agreement include the steps by which the regions and their stakeholders will identify the transmission facilities necessary to meet their needs. Otherwise, NextEra contends that the negotiation of such agreements is likely to be cumbersome. ITC Companies agrees that development of a *pro forma* interregional planning agreement would provide clarity regarding the Commission's minimum requirements and, if designed properly, could avoid replication of flaws in existing transmission planning processes that occurred in the PJM and MISO Joint Operating Agreement. In its reply comments, PJM agrees with ITC Companies that a more standardized planning process that includes a *pro forma* interregional planning agreement could improve coordination with respect to interregional facilities, and cautions that the Commission cannot simply recite regional differences as the basis for not establishing broader criteria. However, PJM contends that ITC Companies' argument regarding the Joint Operating Agreement is likely premised on the fact that their project was not selected in the RTOs' respective regional transmission plans. In its reply, Southern California Edison argues that adopting a *pro forma* agreement is not workable because planning coordination differs significantly at each RTO/ISO and among vertically integrated utilities.

428. Pennsylvania PUC suggests that the joint operating agreement between PJM and MISO, which includes a section on coordinated regional transmission planning requirements, could serve as a model for neighboring transmission regions negotiating bilateral coordination agreements. Pennsylvania PUC warns, however, that the joint operating agreement between PJM and MISO may require improvement in both content and operation with regard to interregional transmission planning and construction.

429. PJM requests that, before requiring greater interregional coordination, the Commission clarify whether it will continue to allow regional differences in transmission planning processes or it intends to require greater standardization among regional planning processes to achieve interregional coordination. Old Dominion agrees, recommending that the Commission provide guidance addressing the extent to which regional differences can be modified to enhance interregional transmission planning—potentially by requiring an interim compliance measure where regions report to the Commission on their progress, identify differences in regional transmission planning and/or cost allocation, and request guidance where needed. Southern Companies states on reply that, while they have no objection to the Commission encouraging additional coordination, the Commission should not attempt to mandate (directly or indirectly) uniformity or standardization. Other commenters urge flexibility to accommodate regional differences.[355]

430. Several commenters emphasize the need for more consistent data formats, modeling, planning assumptions, planning standards and protocols, and evaluation procedures and metrics (among other elements of and tools used in the transmission planning process) between transmission planning regions or for use in interregional transmission planning to ensure that the proposed reforms are effective.[356] East Texas Cooperatives cite examples of inconsistent metrics and assumptions that they contend have hindered effective interregional planning between SPP and Entergy, including the use of: (1) Different metrics to calculate available flowgate capacity at the seams; (2) different planning horizons; and (3) different types of proposed transmission upgrades in the long-term models for granting transmission service. Exelon asks the Commission to require the use of the same modeling assumptions and planning criteria, which should reflect actual expected operating conditions, when studying the impacts of a proposed interregional transmission facility on the reliability and congestion of neighboring systems. WIRES argues for the establishment of common interregional planning protocols by the Commission that can be employed by planners and stakeholders to guide development of interregional agreements on data, assumptions, and procedures that will be the foundation of genuine interregional planning processes. ITC Companies also recommends that the Commission require common assumptions and goals for long-term planning. Minnesota PUC and Minnesota Office of Energy Security recommend that project sponsors be required to provide usable data to all transmission planning entities that must study their projects.

431. Several commenters express concern that interregional planning processes could occur at different times and argue that a timeline should be established such that all planning regions consider interregional projects using the same timeline.[357] MidAmerican argues that interregional planning should be undertaken on a common time horizon, such as 20 years or longer. Organization of MISO States recommends that the Commission consider requiring the establishment of deadlines for submitting an interregional project for joint evaluation to avoid any negative impacts on each individual transmission planning region's planning process. ISO New England, however, argues against requiring interregional projects to be evaluated simultaneously by both regions or in joint sessions of both regions' stakeholders, asking instead that sequential evaluation by each region be allowed. Pioneer Transmission opposes sequential evaluation and recommends that the Commission require that interregional transmission planning agreements include specific milestones to ensure that proposed interregional projects are evaluated in a timely manner. Pioneer Transmission cautions, however, that interregional projects already before a transmission planning region should not be required to start over, which could possibly delay the overall evaluation process. MISO Transmission Owners agree that the proposed requirement should not interfere with existing transmission planning cycles.

432. American Transmission and the MISO Transmission Owners further recommend that interregional coordination procedures must allow for ''out-of-cycle'' reviews of interregional projects to address reliability issues. However, Wisconsin Electric Power Company suggests that the Commission require that adjacent planning regions align the timelines of their regional transmission planning processes to facilitate interregional coordination.

433. Several commenters support the Commission's proposed requirement that a proposed interregional transmission project must be included in each relevant regional transmission plan to be subject to the interregional cost allocation method.[358] Duke supports the proposed requirement

[355] *E.g.,* California Commissions; Dayton Power and Light; and NARUC.

[356] *E.g.,* WIRES; Wisconsin Electric Power Company; Pioneer Transmission; Organization of MISO States; Pennsylvania PUC; 26 Public Interest Organizations; East Texas Cooperatives; and ITC Companies.

[357] *E.g.,* Indianapolis Power & Light; California ISO; Organization of MISO States; and Solar Energy Industries and Large-scale Solar.

[358] *E.g.,* New York ISO; New York Transmission Owners; and Transmission Dependent Utility Systems.

subject to the acknowledgement that inclusion in a plan does not mean that a given project will be constructed. Connecticut & Rhode Island Commissions contend that a region should not be required to accept an allocation of a transmission facility's costs unless the region approved the facility in its planning process and has identified concrete benefits that would accrue to the region. Organization of MISO States asks the Commission to clarify what would happen if, after neighboring regions' joint evaluation of a proposed interregional project, the project were found to benefit one region, but not the other. New England States Committee on Electricity supports the Commission's approach to interregional coordination as long as interregional transmission projects sponsored by one region will not be imposed involuntarily on another region. However, Anbaric and PowerBridge suggest that, once selected to go ahead, an interregional transmission project should bypass the planning region's normal procedures and be assigned to an interregional team to expedite and oversee the project, to ensure timely development of the facilities.

434. First Wind suggests that a region from which renewable energy is to be exported may not experience reliability, economic, or public policy benefits as a result of an interregional transmission project and, thus, the exporting region may not include the project in its regional transmission plan. To ensure that renewable resources are able to access markets in which they can command the best price, First Wind suggests that the regional state committee representing the importing region be able to identify that an interregional transmission project is necessary to achieve public policy objectives and consequently have it included in the exporting region's regional transmission plan.

ii. Commission Determination

435. The Commission requires the development of a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in neighboring transmission planning regions. The establishment of a procedure by which a public utility transmission provider will identify and jointly evaluate is necessary for facilitating the identification of interregional solutions that may resolve each region's needs more efficiently or cost-effectively. As a result, the Commission and transmission customers will have greater certainty that the transmission facilities in each regional transmission plan are the more efficient and cost-effective solutions to meet the region's needs.

436. The Commission also requires the developer of an interregional transmission project to first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located. The submission of the interregional transmission project in each regional transmission planning process will trigger the procedure under which the public utility transmission providers, acting through their regional transmission planning process, will jointly evaluate the proposed transmission project. This joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project. Finally, for an interregional transmission facility to receive cost allocation under the interregional cost allocation method or methods developed pursuant to this Final Rule, the transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation.

437. Some commenters such as ISO/RTO Council express concern that joint evaluation of proposed interregional transmission facilities could involve the creation of a new set of planning criteria, while others such as Exelon stress the need for greater consistency in planning criteria and modeling assumptions used by neighboring regions. As a general matter, we note that joint evaluation of a proposed interregional transmission facility cannot be effective without some effort by neighboring transmission planning regions to harmonize differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed transmission project. We therefore direct, as part of compliance with the interregional transmission coordination requirements, that each public utility transmission provider, through its transmission planning region, develop procedures by which such differences can be identified and resolved for purposes of jointly evaluating the proposed interregional transmission facility. We leave to each pair of neighboring regions, however, discretion in the way this requirement is designed and implemented and do not require that any particular planning horizons or criteria be used. In response to Minnesota PUC and Minnesota Office of Energy Security, we discuss in the opportunities for discrimination against non-incumbent transmission developers section the information that a transmission developer must provide to the transmission planning region in support of its transmission project proposal.[359]

438. Some commenters argue that the Commission should establish the timeframe within which regions must jointly evaluate interregional transmission projects. The Commission declines to specify a timeline for the interregional transmission coordination procedures or a deadline by which all interregional transmission projects must be submitted. Instead, the Commission expects public utility transmission providers in neighboring transmission planning regions to cooperate and develop timelines that allow for coordination and joint evaluation of interregional transmission projects in the same general time frame as each region's consideration of the transmission project. Furthermore, we disagree with those commenters that argue that there should be sequential evaluation of transmission projects, as opposed to evaluation on the regional and interregional levels in the same general time frame. However, we clarify for ISO New England that we will not require that interregional transmission projects be evaluated simultaneously by both regions or in joint sessions of both regions' stakeholders.

439. Rather, we require that both regions conduct joint evaluation of an interregional transmission project in the same general timeframe. By same general time frame, the Commission expects public utility transmission providers to develop a timeline that provides a meaningful opportunity to review and evaluate through the interregional transmission coordination procedures information developed through the regional transmission planning process and, similarly, provides a meaningful opportunity to review and use in the regional transmission planning process information developed in the interregional transmission coordination procedures. Rather than provide further detailed guidance on this matter in this Final Rule that may unduly constrain the planning time line of each region for purposes of coordination with one or several neighboring regions, we prefer in the first instance to permit regions to develop appropriate timing arrangements with neighbors, which we will review on compliance.

440. American Transmission and the MISO Transmission Owners

[359] *See* discussion *supra* section III.B.3.d.ii.

recommend that interregional transmission coordination procedures must allow for ''out-of-cycle'' reviews of interregional transmission projects to address reliability issues. The Commission believes that a requirement for ongoing constant reviews without regard to a defined planning cycle would be too burdensome. This Final Rule does not require such an ''out-of-cycle'' review, nor does it prohibit a region or a pair of regions from doing so, for example if necessary to address a pressing reliability issue. Additionally, while the creation of a new planning cycle may be unnecessary, the Commission is requiring that coordination and joint evaluation must be conducted in the same general time frame as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project.

441. Furthermore, we decline to adopt suggestions to require adjacent transmission planning regions to align the timelines of their regional transmission planning processes. The Commission is providing flexibility, subject to certain requirements, in the design and implementation of procedures to govern the joint evaluation of interregional transmission facilities by neighboring transmission planning regions. To the extent public utility transmission providers in neighboring transmission planning regions identify changes to their regional transmission planning processes that are necessitated by implementation of interregional transmission coordination procedures, those transmission providers should implement those changes as part of their compliance filings submitted in response to this Final Rule.

442. In response to New England States Committee on Electricity's comment that interregional transmission coordination should begin with and respect the regional transmission planning process and resulting regional transmission plan, we note that we require in this Final Rule that the developer of a transmission project that would be located in more than one transmission planning region first must propose its transmission project in the regional transmission planning process of each of those transmission planning regions. We expect each transmission planning region's review of that transmission project to be informed by and closely coordinated with the interregional transmission coordination procedures. Furthermore, the Commission did not propose in the Proposed Rule, and will not require in this Final Rule, that interregional transmission coordination procedures provide for the costs of an interregional transmission project sponsored by one transmission planning region to be involuntarily imposed on another transmission planning region.

443. Finally, the Commission agrees with Duke that having an interregional transmission facility in a regional transmission plan does not mean that it will be constructed. As in Order No. 890, the goal of this Final Rule is to establish procedures by which neighboring transmission planning regions will coordinate to jointly evaluate proposed transmission facilities, not to dictate which investment must be made or transmission projects must be built.[360] In response to Connecticut & Rhode Island Commissions, the Commission clarifies that public utility transmission providers in a transmission planning region will not be required to accept allocation of the costs of an interregional transmission project unless the region has selected such transmission facility in the regional transmission plan for purposes of cost allocation. That is, based on the information gained during the joint evaluation of an interregional transmission project, each transmission planning region will determine, for itself, whether to select those transmission facilities within its footprint in the regional transmission plan for purposes of cost allocation. Whether a transmission planning region would decide to select an interregional transmission facility in its regional transmission plan likely would be driven by the relative costs and benefits of the transmission project to that region. The Commission believes this effectively provides the ''feedback loop'' sought by Old Dominion.

444. The Commission declines to adopt the suggestion by Anbaric and PowerBridge that an interregional transmission project resulting from the interregional transmission coordination procedures be allowed to bypass the relevant regions' transmission planning processes and be automatically assigned to an interregional team. However, we do not preclude the public utility transmission providers in a pair of transmission planning regions from creating a separate process for developing interregional transmission facilities that have been in each relevant transmission planning region's plan. Instead, we provide transmission planning regions with flexibility to determine how to address an interregional transmission project. We reiterate that, to be eligible for interregional cost allocation, the interregional transmission facility must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission facility is proposed to be located.

445. Beyond the clarifications provided above, we decline to address the remaining requests to further delineate how neighboring transmission regions must jointly evaluate proposed interregional transmission facilities because such action could inadvertently impose requirements that are not appropriate for particular regions. Given the flexibility we have provided to public utility transmission providers in implementing the interregional transmission coordination requirements, the Commission determines it is unnecessary to adopt interim compliance requirements or other processes such as those suggested by Old Dominion.

446. We decline to adopt First Wind's suggestion that a transmission planning region should be required to include a transmission project intended to export renewable energy resources in its regional transmission plan if the regional state committee representing the importing region identifies the transmission project as necessary to achieve a public policy objective. As discussed above, whether an interregional transmission facility is to be selected in the regional transmission plan for purposes of cost allocation is a decision left to each transmission planning region. However, we will not preclude public utility transmission providers in neighboring transmission planning regions from voluntarily developing procedures such as those proposed by First Wind should they agree to do so as part of their interregional transmission coordination efforts.

447. In response to commenters' recommendations that the Commission provide for regional flexibility in developing and implementing interregional transmission coordination, we reiterate the Commission's encouragement in the Proposed Rule that interregional transmission coordination procedures be tailored to best fit the needs of the public utility transmission providers in the regions involved while also meeting certain minimum requirements.[361]

448. Furthermore, as urged by PUC of Nevada, we are cognizant of existing

[360] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438.

[361] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 117.

interregional transmission coordination efforts and, by providing regional flexibility, intend to accommodate their various organizational structures, as suggested by WestConnect Planning Parties. Consistent with this approach, any public utility transmission provider that believes its existing interregional transmission coordination procedures, including those found in any interregional transmission planning agreement, already comply with the requirements of this Final Rule may indicate in its compliance filing how its existing procedures meet each requirement. If the existing procedures do not meet all of the requirements, the public utility transmission provider may propose revisions to its existing interregional transmission coordination procedures so that the procedures comply with this Final Rule.

449. Because we want to allow for regional flexibility, we decline to adopt commenters' suggestions that the Commission develop *pro forma* interregional transmission coordination procedures or impose additional requirements as to what interregional transmission coordination should entail. As noted by Southern California Edison, planning coordination differs significantly at each RTO and ISO and among vertically integrated utilities, and we thus determine that *pro forma* interregional transmission coordination procedures are not appropriate at this time because it may not accommodate the differences among existing transmission planning regions. Moreover, the requirements that we adopt as interregional transmission coordination requirements in this Final Rule should be adequate guidance for public utility transmission providers.

450. We also note the Pennsylvania PUC's suggestion that the joint operating agreement between PJM and MISO, which includes a section on coordinated regional transmission planning requirements, could serve as a model for neighboring transmission planning regions negotiating bilateral coordination agreements. While we generally agree that various existing transmission planning agreements between regions may serve as models, we note that existing agreements reflect the needs of the regions that negotiated them. Thus, the Commission declines to require public utility transmission providers to adopt or model their coordination procedures on any particular agreement to coordinate transmission planning between two regions.

b. Data Exchange

i. Comments

451. American Transmission supports the Proposed Rule's requirement that interregional transmission planning agreements include an agreement to exchange planning data and information at least annually. American Transmission states that this requirement would help ensure that neighboring regions are aware of planning considerations as well as any transmission issues in neighboring regions. It also recommends that the Commission establish a time frame for a neighboring transmission planning region to respond to a transmission provider's request for planning information and data. SPP recommends that the Commission require interregional transmission planning agreements to include the specific procedures for sharing such information rather than only an agreement to do so.

452. Several commenters state that this exchange should be required to occur more often than annually.[362] NextEra states that the Commission should require the exchange of planning data and information at least as frequently as warranted by any material developments that either affect any neighboring region or interregional facility or may influence any interregional transmission plan. Organization of MISO States recommends that the Commission modify this element to require exchange of planning data and information at least semi-annually because transmission planning analysis can change over the course of a planning cycle due in part to changing modeling results and stakeholder input. Minnesota PUC and Minnesota Office of Energy Security recommend that the Commission require planning data and information exchanges between transmission planning regions to occur semi-annually to account for those project proposals that are requested to be reviewed out-of-cycle.

453. Transmission Dependent Utility Systems and Pennsylvania PUC express concern that this proposed element does not consider differences in the planning processes of each region. For example, Transmission Dependent Utility Systems state that the proposed planning data and information exchange requirement may be inadequate to address interregional transmission infrastructure concerns, and that transmission providers and stakeholders should be permitted to determine the type and frequency of meetings and planning information exchanges. Likewise, Pennsylvania PUC states that this requirement should accommodate different transmission planning regions' planning cycles.

ii. Commission Determination

454. The Commission requires each public utility transmission provider, through its regional transmission planning process, to adopt interregional transmission coordination procedures that provide for the exchange of planning data and information at least annually. The sharing of data at least once a year will ensure that neighboring transmission planning regions are aware of each others' transmission plans and the assumptions and analysis that support such plans. In response to arguments that the Commission should require neighboring transmission planning regions to exchange data more frequently, we note that this Final Rule provides that this information must be exchanged *at least* annually, thereby allowing each public utility transmission provider through its transmission planning region, the flexibility to decide to exchange information more frequently. If a pair of transmission planning regions anticipates that more frequent exchanges of planning data and information would improve interregional transmission coordination, then we encourage them to provide for such exchanges in their interregional transmission coordination procedures.

455. We agree with SPP that interregional transmission coordination procedures must include the specific obligations for sharing planning data and information rather than only an agreement to do so. A clear description of the procedures that will be used to exchange planning data and information will help the Commission, transmission customers, and other stakeholders to better determine if each public utility transmission provider is fulfilling its obligations consistent with this Final Rule. However, we will not dictate the specific procedures or the level of detail for the procedures pursuant to which planning data and information must be exchanged. Consistent with the comments of Transmission Dependent Utility Systems and Pennsylvania PUC, we allow each public utility transmission provider, through its transmission planning region, to develop procedures to exchange planning data and information, which we anticipate will reflect the type and frequency of meetings that are appropriate for each pair of regions and

[362] *E.g.,* Minnesota PUC and Minnesota Office of Energy Security; NextEra; and Organization of MISO States.

will accommodate each pair of region's planning cycles.

c. Transparency

i. Comments

456. Pennsylvania PUC supports the proposed requirement that interregional transmission planning agreements include a commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated planning process. Duke requests the Commission clarify that information relating to the interregional transmission planning process can be maintained on an existing transmission provider's Web site or regional transmission planning Web site.

457. In addition, MISO Transmission Owners suggest that all transmission providers offering transmission service or interconnection service under a tariff (including a non-jurisdictional tariff) should be required to make publicly available their business practice manuals or other documentation specifically detailing the assumptions and criteria used in comparably evaluating all proposed transmission and generation projects, including the identification and treatment of third-party impacts.

ii. Commission Determination

458. The Commission requires public utility transmission providers, either individually or through their transmission planning region, to maintain a Web site or e-mail list for the communication of information related to interregional transmission coordination procedures. The Commission clarifies that information related to interregional transmission coordination may be maintained on an existing public utility transmission provider's Web site or a regional transmission planning Web site. However, the information should be posted in such a way that stakeholders are able to distinguish between information related to interregional transmission coordination and information related to regional transmission planning.

d. Stakeholder Participation

i. Commission Proposal

459. In the Proposed Rule, the Commission did not specifically address the issue of stakeholder participation with regard to the coordination of transmission planning activities undertaken by neighboring transmission regions.

ii. Comments

460. Some commenters discuss the need for utilities and stakeholders to participate in the process of developing interregional planning agreements. Transmission Access Policy Study Group states that interregional transmission planning agreements must be inclusive, open, and collaborative. Both Transmission Access Policy Study Group and East Texas Cooperatives state that transmission dependent utilities should have the opportunity to participate in their development and implementation. Transmission Access Policy Study Group states that, without such a requirement, the Commission would not be fulfilling its responsibility under FPA section 217(b)(4) to facilitate planning to meet the needs of all load-serving entities. Wisconsin Electric Power Company requests that the Commission explicitly ensure that stakeholders have the opportunity to participate in the development of these agreements.

461. Some commenters contend that the interregional transmission planning requirements described in the Proposed Rule could be significantly improved with respect to stakeholder participation. New York PSC states that the Commission should articulate that meaningful participation in the planning process is necessary, including the opportunity to provide input concerning how studies are conducted and solutions are identified. Transmission Dependent Utility Systems contend that it is just as important for transmission customers to be able to participate in interregional transmission planning as it is for them to be able to participate in regional transmission planning.

462. Integrys states that because stakeholder involvement and input is necessary to ensure proper planning and evaluation of projects, the Commission should adopt a stakeholder participation requirement in any Final Rule. Xcel states that the interregional coordination necessary to support the development of larger-scale, interregional transmission projects (particularly those that are needed to integrate renewable energy resources) must engage stakeholders, and especially state regulatory agencies, in the development of processes that address the specific needs and requirements of the participating regions. Without the involvement of state agencies, which ultimately decide which transmission facility will be built, Xcel contends that interregional transmission planning processes will not result in the construction of needed transmission.

463. Energy Future Coalition states that interregional transmission planning must be both participatory and analytically robust by engaging all interested parties, including utilities, states, renewable generation developers, environmental interests, and consumer interests.

464. Some commenters express concern that, even if the proposed interregional transmission planning requirements provide for stakeholder participation, such participation can require significant resources from stakeholders. NARUC and Massachusetts Departments claim that limited human resources and budgets make it difficult for state commissions and other stakeholders to participate in additional transmission planning processes. Massachusetts Departments suggest that any Final Rule should take these challenges into account and consider mechanisms to address them. Similarly, California Commissions comment that states must have access to adequate resources to support state involvement in interregional coordination processes and that the Commission could consider requiring stakeholder support beyond that provided through the ARRA-funded interconnectionwide transmission planning initiatives.

iii. Commission Determination

465. We agree with those commenters that argue stakeholder participation is an important component in interregional transmission coordination to ensure the goals of improving coordination between neighboring transmission planning regions and identifying interregional transmission facilities that can address transmission needs more efficiently or cost-effectively than separate intraregional transmission facilities. However, this Final Rule does not require the interregional transmission coordination procedure to meet the requirements of the planning principles required for local planning (under Order No. 890) and regional planning (under this Final Rule).[363] Because we require in this Final Rule that an interregional transmission facility must be selected in each relevant regional transmission plan for purposes of cost allocation to be eligible for interregional cost allocation, stakeholders will have the opportunity to participate fully in the consideration of interregional transmission facilities during the regional transmission

[363] Of course, nothing precludes public utility transmission providers in neighboring transmission planning regions from choosing to meet those requirements.

planning process.[364] Furthermore, we believe that stakeholder participation in the various regional transmission planning processes will enhance the effectiveness of interregional transmission coordination. To facilitate stakeholder involvement, this Final Rule requires the public utility transmission providers to make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[365]

466. We also agree with commenters that discuss the importance of transmission customer and stakeholder participation in the development of the interregional transmission coordination procedures necessary to comply with the requirements in this Final Rule. Therefore, we require that each public utility transmission provider give stakeholders the opportunity to provide input into the development of its interregional transmission coordination procedures and the commonly agreed-to language to be included in its OATT.

467. The Commission appreciates the concerns of NARUC and others regarding the effect budgetary limitations could have on effective stakeholder participation in interregional transmission coordination activities. As discussed above in the regional transmission planning section [366] and consistent with Order No. 890, to the extent that public utility transmission providers choose to include a funding mechanism to facilitate the participation of state consumer advocates or other stakeholders in the regional transmission planning process, nothing in this Final Rule precludes them from doing so.

e. Tariff Provisions and Agreements for Interregional Transmission Coordination

i. Commission Proposal

468. In the Proposed Rule, the Commission proposed to require that coordination between neighboring transmission planning regions be reflected in an interregional transmission planning agreement to be filed with the Commission.[367]

ii. Comments

469. Several commenters express support for the Commission's proposal to require neighboring regions to enter into interregional transmission planning agreements.[368] They also emphasize, however, that planning regions should be able to structure planning agreements so that each region is a full, equal partner and no region can force projects or costs onto other regions in a manner that is inconsistent with the agreement. Edison Electric Institute further emphasizes that these planning agreements cannot replace strong interregional coordination to address interregional impacts.

470. Other commenters argue that the Commission should accept the submission of existing interregional agreements, with necessary modifications, to comply with the Final Rule.[369] American Transmission and MISO Transmission Owners state that when reviewing existing interregional agreements to determine their compliance with the Final Rule, if the Commission determines that modifications to these agreements are necessary, the public utility transmission providers and their stakeholders should be given the opportunity to address and submit revisions.

471. Some commenters suggest that interregional coordination procedures should be incorporated into public utility transmission providers' OATTs. Ad Hoc Coalition of Southeastern Utilities suggests that as an alternative to the interregional agreement, the Commission should consider adopting an additional planning principle that permits public utility transmission providers to explain how they address the types of matters that the Proposed Rule would require to be included in such interregional agreements. ColumbiaGrid further contends that transmission providers in the Western Interconnection should be required to include in their OATTs only the regional planning group and WECC processes and information regarding their existing relationship, and that they should not be required to divert resources to developing formal agreements to be filed with the Commission. Bonneville Power suggests that the Commission require transmission providers to include coordination requirements as part of the transmission planning processes outlined in their OATTs, but without specific details about how individual projects would be planned and developed. It states that this would allow transmission providers to enter into voluntary agreements and to focus on developing higher priority projects. Transmission Dependent Utility Systems state that each public utility transmission provider's interregional transmission planning process should be included in the OATT, subject to effective Commission and stakeholder scrutiny on an ongoing basis.

472. California ISO also contends the proposed requirements are problematic for the ISO in that it would not be able to develop an interregional transmission planning agreement applicable to all of its neighboring balancing authority areas because many of its neighboring balancing authorities have different legal charters and are subject to different laws, regulations, and requirements.

473. Several commenters raised concerns about the proposed interregional transmission planning agreements with respect to non-jurisdictional transmission providers. Western Area Power Administration requests that the Final Rule acknowledge that interregional transmission planning-related agreements would need to account for the status and statutory requirements of non-public utility transmission providers before they may be executed. Large Public Power Council states its members will commit to voluntarily participate in interregional transmission planning processes, but that its members have limited authority to enter into agreements that include, among other things, an obligation to pay construction costs or a requirement to defer to regional or interregional planning authorities. Omaha Public Power District states that it plans to participate voluntarily in an interregional transmission planning process, but notes that its agreements to do so would not be subject to the Commission's jurisdiction or enforcement. Nebraska Public Power District expresses the same concerns regarding the lack of clarity in the commitments that it would be required to make as a result of the proposed interregional transmission planning agreements. Nebraska Public Power District also commits to participate in interregional transmission planning processes; however, it contends that it cannot make such commitment outside of its current RTO membership and the related protection against violating state law and that its authority to enter into binding agreements is limited consistent with state sovereignty.[370]

[364] *See* discussion *supra* P 0.

[365] This information must be made available subject to appropriate confidentiality protections and CEII requirements.

[366] *See* discussion *supra* section III.A.3.

[367] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 114.

[368] *E.g.,* National Grid; New York Transmission Owners; and Edison Electric Institute.

[369] *E.g.,* FirstEnergy Service Company; American Transmission; and MISO Transmission Owners.

[370] Comments addressing specific statutory provisions that may limit non-jurisdictional

Continued

474. Several commenters argue that the Commission should require non-jurisdictional entities to comply with the proposed interregional transmission planning requirements. Westar states that power flows on a non-jurisdictional entity's system can affect facilities in a jurisdictional entity's system, and vice-versa. Similarly, MISO Transmission Owners state that requiring non-jurisdictional entities to participate would ensure effective interregional transmission planning and coordination and address seams issues. NextEra states that to facilitate broad-based participation by all relevant entities, the Commission should invoke its authority under FPA section 211A to require unregulated transmitting utilities to participate in the interregional transmission planning process.

iii. Commission Determination

475. In light of the comments received, the Commission declines to require that coordination between the public utility transmission providers in pairs of neighboring transmission planning regions be reflected in a formal interregional transmission planning agreement filed with the Commission, as was proposed in the Proposed Rule. Instead, as recommended in part by Ad Hoc Coalition of Southeastern Utilities, ColumbiaGrid, Bonneville Power, and Transmission Dependent Utility Systems, we require that the public utility transmission providers in each pair of neighboring transmission planning regions, working through their regional transmission planning processes, must develop the same language to be included in each public utility transmission provider's OATT that describes the interregional transmission coordination procedures for that particular pair of regions.[371] Alternatively, if the public utility transmission providers so choose, these procedures may be reflected in an interregional transmission coordination agreement filed on compliance for approval by the Commission.[372]

476. We find that implementing the interregional transmission coordination requirements in this Final Rule through their incorporation in each public utility transmission provider's OATT, instead of requiring an interregional transmission planning agreement, will fulfill our objective to improve interregional transmission coordination and provide adequate transparency with regard to the obligations imposed on public utility transmission providers. Further, commenters persuade us that this approach would facilitate the participation of non-public utility transmission providers in an interregional transmission coordination efforts.

477. In response to commenters' arguments that the Commission should accept the submission of existing interregional agreements on compliance, we agree provided the compliance filing explains how the existing agreement satisfies the requirements of this Final Rule. The Commission will address the adequacy of such an existing agreement on compliance.

478. We decline to adopt Bonneville Power's recommendation that these procedures omit specific details about how individual transmission projects would be planned and developed, because we require each set of interregional transmission coordination procedures to include a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions.

479. We do not find convincing California ISO's argument that it will be problematic for it to develop interregional transmission coordination procedures with all of its neighboring balancing authority areas due to the differences among them. Just as reliable transmission operation of interconnected transmission systems requires coordination among neighboring utilities and regions—some of which is required by mandatory reliability standards, transmission planning of interconnected transmission systems requires some degree of coordination among neighboring utilities and regions. We conclude that this Final Rule provides for sufficient regional flexibility to allow the California ISO to develop in cooperation with its neighboring balancing authority areas interregional transmission coordination procedures that accommodate their differences.

480. We agree with commenters that interregional transmission coordination should be structured in such a way that no public utility transmission provider in a transmission planning region should be permitted to force transmission projects or costs onto another region contrary to the agreed upon interregional transmission coordination procedures incorporated into the relevant public utility transmission providers' OATTs pursuant to this Final Rule.

481. Because we are implementing the interregional transmission coordination requirements adopted in this Final Rule through incorporation of the same language into each public utility transmission provider's OATT rather than through formal agreements, we find comments presenting concerns that non-public utility transmission providers are unable to be party to interregional transmission planning agreements to be moot. Furthermore, we do not believe that it is necessary to address here those commenters that ask us to require non-public utility transmission providers to participate in interregional transmission coordination efforts. We believe such concerns are premature, as we are encouraged by the non-public utility transmission providers who expressed their intent to participate in interregional transmission coordination efforts in their comments in response to the Proposed Rule. Additional discussion of non-public utility transmission provider participation in the reforms adopted in this Final Rule, including the interregional transmission coordination requirements, is in the reciprocity section below.[373]

IV. Proposed Reforms: Cost Allocation

482. The Commission requires, as part of this Final Rule, that each public utility transmission provider have in its OATT a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan (''regional cost allocation''); and that each public utility transmission provider within a transmission planning region develop a method or set of methods for allocating the costs of new interregional transmission facilities that two (or more) neighboring transmission planning regions determine resolve the individual needs of each region more efficiently

participation in this regard are addressed in the discussion of the Commission's legal authority to undertake reforms regarding regional transmission planning. *See* discussion *infra* section III.A.2 of this Final Rule.

[371] Consistent with the approach taken in Order Nos. 890 and 890–A, public utility transmission providers may use Web-posted business practice manuals to describe planning-related processes. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1653; Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 990.

[372] However, even if a public utility transmission provider voluntarily enters into such an agreement, its OATT must still provide enough description for stakeholders to follow how interregional transmission coordination will be conducted, with links included to the actual agreement where the details can be found. *See United States Dep't of Energy—Bonneville Power Admin.,* 124 FERC ¶ 61,054, at P 65 (2008) (requiring Avista, Puget and Bonneville Power ''to provid[e] additional detail in their Attachment Ks on the WECC's [Transmission Expansion Planning Policy Committee's] process or providing direct links (*i.e.,* URLs) to the appropriate documents on the WECC Web site where the processes to coordinate information and planning efforts [between several regional planning groups] are discussed'').

[373] *See* discussion *infra* section V.B.

and cost-effectively (''interregional cost allocation''). The OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region. Each of the regional cost allocation and interregional cost allocation methods must adhere to the respective general cost allocation principles as set forth below.[374] Subject to these general cost allocation principles, public utility transmission providers in consultation with stakeholders have the opportunity to develop the appropriate cost allocation methods for their new regional and interregional transmission facilities. In the event that no agreement among public utility transmission providers in a region or pair of regions can be reached, the Commission will use the record in the relevant compliance filing proceeding(s) as a basis to develop a cost allocation method or methods that meets the Commission's requirements.

483. The requirements established below are designed to work in tandem with the transmission planning requirements established above to identify more appropriately the benefits and the beneficiaries of new transmission facilities so that transmission developers, planners and stakeholders can take into account in planning who would bear the costs of transmission facilities, if constructed.

A. Need for Reform Concerning Cost Allocation

1. Commission Proposal

484. In the Proposed Rule, the Commission noted that its responsibility under sections 205 and 206 of the FPA to ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential is not new, nor is the Commission's recognition of the cost causation principle. However, the Commission explained that the circumstances in which it must fulfill its statutory responsibilities change with developments in the industry, such as changes with respect to the demands placed on the grid. For example, the expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions. Similarly, the increasing adoption of state resource policies, such as renewable portfolio standards, has contributed to the rapid growth of renewable energy resources that are frequently remote from load centers.

485. The Commission stated that challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. The Commission noted that constructing new transmission facilities requires a significant amount of capital and, therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. The Commission explained, however, that there are few rate structures in place today that provide both for analysis of the beneficiaries of a transmission facility that is proposed to be located within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region, and for corresponding allocation and recovery of the facility's costs. The Commission stated that lack of such rate structures creates significant risk for transmission developers that they will have no identified group of customers from which to recover the cost of their investment. With regard to cost allocation within RTO or ISO regions, the Commission noted that cost allocation issues are often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair, particularly for RTOs and ISOs that encompass several states.

486. The Commission further noted that the risk of the free rider problems associated with new transmission investment is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. The Commission explained that, on one hand, a cost allocation method that relies exclusively on a participant funding approach,[375] without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner. On the other hand, if costs would be allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose selection of the facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the facility's construction.

487. In light of these challenges and recent developments affecting the industry, the Commission stated concern that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities and, thus, may result in rates that are not just and reasonable or are unduly discriminatory or preferential.[376] The Commission proposed the cost allocation requirements discussed in further detail below to address this concern.

2. Comments on Need for Reform

488. A number of commenters generally support the cost allocation requirements proposed by the Commission.[377] For example, ITC Companies state that the Commission has correctly concluded that reform with respect to transmission cost allocation methods is necessary. AWEA argues that issues related to cost allocation impede transmission development required to address increased demand, meet national energy and environmental goals, and create an intelligent, secure, and reliable transmission network. Clean Line argues that implementation of a cost allocation method is critical to the development of new infrastructure. Multiparty Commenters argue that a fair allocation of the costs of new transmission can be facilitated by acknowledging that the cost of transmission is a small portion of the delivered cost of electricity, generally ten percent or less, whereas the costs of a single project may be significant for the builders of that project. Solar Energy Industries urge the Commission to use its authority to alleviate impediments to building new transmission lines for renewable energy and other system needs to promote a robust competitive market that will benefit consumers and the environment.

[374] For purposes of this Final Rule, a regional transmission facility is a transmission facility located entirely in one region. The Proposed Rule sometimes called such a facility a regional facility and sometimes an intraregional facility. An interregional transmission facility is one that is located in two or more transmission planning regions. A transmission facility that is located solely in one transmission planning region is not an interregional transmission facility.

[375] Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. The Proposed Rule cited several examples of regions relying principally or exclusively on the participant funding approach to cost allocation. Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128.

[376] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 148–54.

[377] *E.g.,* Transmission Access Policy Study Group; AWEA; Northeast Utilities; ITC Companies; Energy Future Coalition Group; MidAmerican; MISO; NextEra; E.ON Climate Renewables North America; Exelon; Iberdrola Renewables; WIRES; Western Grid Group; and Pennsylvania PUC.

489. Many commenters also support aligning transmission planning and cost allocation more closely.[378] Transmission Dependent Utility Systems state that it is virtually impossible to separate transmission planning from transmission cost allocation. Exelon argues that fair, efficient, and legal cost allocation should follow the manner in which its system is planned. Integrys agrees with linking cost allocation rules with transmission planning, but cautions that the transmission planning process is not a substitute for the cost allocation process.

490. A number of commenters supporting closer alignment between planning and cost allocation state that existing ISO and RTO transmission planning and cost allocation processes already may satisfy the proposal to align transmission planning and cost allocation more closely.[379] AEP and SPP believe that their existing transmission planning and cost allocation processes satisfy many of the Commission's proposed requirements. Similarly, MISO Transmission Owners state that cost allocation in MISO is already closely tied to the transmission planning process. Organization of MISO States points to MISO filings that address cost allocation issues.

491. WIRES asks the Commission to ensure that the planning process not be unduly influenced by those that seek to redirect potential cost allocation liability. Illinois Commerce Commission believes it is unduly discriminatory for a state to be required to bear costs for transmission expansion projects under a cost sharing arrangement but have no decisional authority for projects outside their state. Where a regional state committee exists, Illinois Commerce Commission recommends that a process be carved out by which the regional state committee's board of directors has the opportunity to review and decide on the reasonableness of each of the RTO's proposed transmission expansion projects for which regional cost allocation would apply.

492. A number of commenters express concern with the Commission's proposal to impose generic regional and interregional cost allocation requirements.[380] Some commenters argue specifically that there is no need for the Commission's proposed cost allocation reforms.[381] For example, Northern Tier Transmission Group argues that the Proposed Rule does not present a factual basis for expanding the scope of the cost allocation requirement to every project contained in a regional transmission plan. It requests that the Commission confirm that the Proposed Rule is not intended to apply to existing transmission projects covered by existing tariff-based and contract-based cost allocation procedures. If the Proposed Rule is intended to apply to all new transmission projects in a region's transmission plan, Northern Tier Transmission Group urges that the Proposed Rule be rejected. It also is concerned that shifting the burden of cost allocation for every project onto the regional transmission planning process will create an unnecessary burden on a region's collective transmission providers. Westar states that the transmission planning selection process is critical to ensure that only transmission projects that meet the various regional requirements are constructed and their costs recovered as part of tariff rates.

493. North Carolina Agencies contend that the Commission has not established that current cost allocation methods are unjust and unreasonable. Nebraska Public Power District argues that the Proposed Rule does not contain any record evidence demonstrating the need for generic rate reform and states that transmission investment has substantially increased in recent years. Salt River Project argues that the primary barriers to renewable resource development are delays and denial of siting and other permits, not transmission funding. California Municipal Utilities suggest that fewer remote resources are needed because more local renewable resources are being developed and, therefore, the need for cost allocation reforms must be re-examined. Indianapolis Power and Light believes that existing tariff requirements and ongoing proceedings will achieve the Commission's stated objective without the uncertainty of a parallel rulemaking process.

494. MEAG Power responds to Multiparty Commenters' assertion regarding the cost of transmission expansion by arguing that investments of the size actually needed to build out the transmission system, if allocated to load, would raise its native load customers' transmission costs dramatically. Sacramento Municipal Utility District states that, even if Multiparty Commenters' assertion were true, it is irrelevant to the establishment of a just and reasonable transmission rate whether it comprises a small or large portion of the cost of delivered power.[382] Large Public Power Council raises arguments similar to those raised by both MEAG Power and Sacramento Municipal Utility District.

3. Commission Determination

495. The Commission concludes that it is necessary and appropriate to adopt the cost allocation requirements described in further detail below for public utility transmission providers. The Commission finds that, without these minimum requirements in place, cost allocation methods used by public utility transmission providers may fail to account for the benefits associated with new transmission facilities and, thus, result in rates that are not just and reasonable or are unduly discriminatory or preferential.

496. In Order No. 890, the Commission found that there is a close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan.[383] The Commission explained that knowing how the costs of transmission facilities would be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.[384] In light of that relationship, the Commission directed public utility transmission providers to identify the cost allocation method or methods that would apply to transmission facilities that do not fit under previously existing rate structures.[385] After several rounds of compliance filings, the Commission accepted various public utility transmission providers' proposals as in compliance with Order No. 890. Particularly in transmission planning regions outside of the RTO and ISO

[378] *E.g.,* Atlantic Grid; ITC Companies; Sunflower and Mid-Kansas; MISO; Pennsylvania PUC; PHI Companies; Colorado Independent Energy Association; Energy Future Coalition Group; PSC of Wisconsin; CapX2020; and Wind Coalition.

[379] *E.g.,* SPP; AEP; MISO Transmission Owners; Organization of MISO States; California PUC; and Pacific Gas & Electric.

[380] *E.g.,* Arizona Public Service Company; Bonneville Power; California Transmission Planning Group; Tucson Electric; Western Area Power Administration; California Commissions; California ISO; Eastern Massachusetts Consumer-Owned System; New York PSC; Coalition for Fair Transmission Policy; Connecticut & Rhode Island Commissions; Large Public Power Council; National Grid; and Southern California Edison.

[381] *E.g.,* Ad Hoc Coalition; Southern Companies; Salt River Project; and Nebraska Public Power District.

[382] Sacramento Municipal Utility District (citing *Farmers Union Central Exchange* v. *FERC,* 734 F.2d 1486, 1508 (DC Cir. 1984)).

[383] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

[384] *Id.*

[385] *Id.* P 558.

footprints, several of the cost allocation methods that the Commission accepted relied exclusively on a participant funding approach to cost allocation.[386] The Commission did not address cost allocation for interregional transmission facilities in Order No. 890.

497. We conclude that, in light of changes within the industry and the implementation of other reforms in this Final Rule, the existing requirements of Order No. 890 are no longer adequate to ensure rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. While the existing cost allocation methods may have sufficed in the past, as we note above, the circumstances in which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, such as changes with respect to the demands placed on the transmission grid. The comments in this proceeding make clear that the pace of change has accelerated in recent years, such as the expansion of regional power markets, which has led to a growing need for transmission facilities that cross several utility, RTO, ISO or other regions. The industry's continuing transition also has enabled greater utilization of resources (*e.g.,* reserve sharing) resulting in, among other effects, broader diffusion of the benefits associated with transmission facilities. Additionally, the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of renewable energy resources that are frequently remote from load centers, and thus a growing need for transmission facilities to access remote resources, often traversing several utility and/or ISO/RTO regions.

498. The challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. Within RTO or ISO regions, particularly those that encompass several states, the allocation of transmission costs is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived by all stakeholders as reflecting a fair distribution of benefits. In other regions, few rate structures are currently in place that reflect an analysis of the beneficiaries of a transmission facility and for the corresponding cost allocation of the transmission facility's cost. Similarly, there are few rate structures in place today that provide for the allocation of costs of interregional transmission facilities.

499. We agree with many commenters that the lack of clear *ex ante* cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process. Under the regional transmission planning and interregional transmission coordination requirements adopted in this Final Rule,[387] public utility transmission providers, in consultation with stakeholders, will identify, evaluate, and determine the set of transmission facilities that will meet the combined needs of the region or neighboring pairs of regions, respectively. This necessarily includes a determination by the region that the benefits associated with that set of transmission facilities outweigh the costs. Failing to address the allocation of costs for these transmission facilities in a way that aligns with the evaluation of benefits through the transmission planning process could lead to needed transmission facilities not being built, adversely impacting ratepayers.

500. In general and as discussed elsewhere in this Final Rule, the Commission requires a public utility transmission provider to participate in a regional transmission planning process and to coordinate transmission planning with public utility transmission providers in neighboring transmission planning regions in a manner that aligns transmission planning and cost allocation processes. Additionally, the OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region. As some commenters point out, transmission facilities that are in a transmission plan to achieve a specific purpose or purposes, such as to avoid an impending violation of a Reliability Standard, address economic considerations, or enable compliance with Public Policy Requirements. Because such purposes involve the identification of expected beneficiaries, either explicitly or implicitly, establishing a closer link between transmission planning and cost allocation will ensure that rates for Commission-jurisdictional service appropriately account for benefits associated with new transmission facilities.

501. We recognize that identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. We believe that a transparent transmission planning process is the appropriate forum to address these issues. By linking transmission planning and cost allocation through the transmission planning process, we seek to increase the likelihood that transmission facilities in regional transmission plans are actually constructed.

502. Turning to specific comments on this topic, we are not persuaded to adopt Illinois Commerce Commission's proposal for separate review and decision by a committee of state regulators on the reasonableness of proposed transmission expansion projects for which regional cost allocation would apply. As explained above,[388] this Final Rule builds on Order No. 890's requirement that a public utility transmission provider have open and transparent transmission planning processes in which we encourage states or state committees to be involved. Additionally, as required by this Final Rule, through the transmission planning process, the public utility transmission providers and other parties, including state regulators, will have opportunities to participate in the identification of transmission needs. We decline, however, to mandate veto rights for state committees, but do not preclude public utility transmission providers from proposing such mechanisms on compliance if they choose to do so.[389]

503. In response to Northern Tier Transmission Group's concern that applying the new cost allocation requirements to existing transmission projects covered by existing tariff-based and contract-based cost allocation procedures will shift costs and create unnecessary burdens, we clarify that the cost allocation requirements of this Final Rule apply only to new transmission facilities[390] selected in regional transmission plans for purposes of cost allocation.

[386] *See, e.g., El Paso Electric Co.,* 124 FERC ¶ 61,051 (2008); *Xcel Energy Services, Inc.—Public Service Co. of Colorado,* 124 FERC ¶ 61,052 (2008); *South Carolina Electric & Gas Co.,* 127 FERC ¶ 61,275 (2009). *Entergy Services, Inc.,* 127 FERC ¶ 61,272 (2009). *See also Avista Corp.,* 128 FERC ¶ 61,065 (2009); *Idaho Power Co.,* 128 FERC ¶ 61,064 (2009).

[387] *See* discussion *supra* sections III.A and III.C.

[388] *See* discussion *supra* section III.A.

[389] For example, Entergy's OATT allows Entergy's committee of state regulators to add a project to Entergy's transmission plan upon unanimous vote of the committee members. *See Entergy Arkansas, Inc.,* 133 FERC ¶ 61,211 (2010).

[390] *See* discussion *supra* P 0.

B. Legal Authority for Cost Allocation Reforms

1. Commission Proposal

504. The Commission explained in the Proposed Rule that, to ensure that transmission rates are just and reasonable, the costs of jurisdictional transmission facilities must be allocated in a way that satisfies the ''cost causation'' principle. It noted that the DC Circuit defined the cost causation principle stating that ''it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.'' [391] Moreover, the Commission noted that while the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it,[392] the DC Circuit has explained that cost causation ''does not require exacting precision in a ratemaking agency's allocation decisions.'' [393]

505. The Commission explained that, while costs generally have been allocated through voluntary agreements, the cost causation principle is not limited to such arrangements. If it were, the Commission could not address free rider problems associated with new transmission investment and could not ensure that transmission rates are just and reasonable and not unduly discriminatory. The Commission stated that it may determine that an entity is a beneficiary of a transmission facility even if it has not entered a voluntary arrangement with the public utility transmission provider that is seeking to recover the costs of that transmission facility.

506. The Commission noted that it has expressed a willingness to make such a determination, as when presented with concerns about parallel path flow.[394] In such cases, a public utility transmission provider may propose a transmission service rate that would account for unauthorized use of its system.[395] The Commission noted that it has cautioned against the hasty submittal of such unilateral filings and prefers resolution of parallel path flow issues on a consensual, regional basis.[396] If necessary, however, it would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement.

507. The Commission also stated that it has affirmatively required costs of transmission facilities to be allocated to beneficiaries in the absence of a voluntary arrangement in a series of orders involving MISO and PJM. Specifically, the Commission explained that it directed MISO and PJM to develop cost allocation methods for new facilities in one of their footprints that benefit entities in the other's footprint.[397] It subsequently conditionally accepted a proposal by MISO and PJM on the grounds that it ''more accurately identifies the beneficiaries and allocates the associated costs.'' [398]

508. The Commission noted that courts have accepted the application of the cost causation principle in this way. For example, the DC Circuit addressed this issue in connection with a MISO proposal to recover administrative costs through a charge that would apply to transmission loads subject to MISO's OATT rates.[399] The court found that the Commission's system-wide benefits analysis met the requirements of the cost causation principle, that is, to compare ''the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' [400]

2. Comments on Legal Authority

509. Several entities comment in support of the Commission's legal authority to allocate costs of new transmission facilities based on a beneficiary pays approach.[401] AEP asserts that the Commission's proposed cost allocation principles comport with the legal requirements on cost allocation articulated by the U.S. Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission* v. *FERC*.[402] Further, AEP states that while the courts have found that the allocation of transmission expansion costs in rates must follow the ''cost causation'' principle, the courts have explained that all beneficiaries ''cause'' costs for the purpose of applying this principle. Thus, from AEP's perspective, the Commission's proposal to require allocation of costs to beneficiaries is fully consistent with the legal precedent. Iberdrola Renewables and American Transmission agree. American Transmission cautions, however, that care be taken in how precisely the costs of a transmission project are linked to beneficiaries, given that the benefits and beneficiaries of a particular project may change over time, particularly in the case of a large project that provides regional and interregional benefits. Allegheny Energy Companies state that although the *Illinois Commerce Commission* decision found that the Commission did not provide sufficient evidence to justify adoption of the postage-stamp cost allocation method in PJM, it did not reject the method outright, instead requiring the Commission only to provide further justification assuring that this method results in a just and reasonable rate that satisfies the principle that rates required to be paid by a customer must have some relationship to the costs caused or benefits received by that customer.

510. LS Power asserts that there is nothing in the FPA that precludes the Commission from allocating costs incurred by one transmission provider in a region to entities nominally taking service under the tariffs of other transmission providers, or to those other transmission providers themselves for

[391] *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (DC Cir. 1992) (*K N Energy*).

[392] *Illinois Commerce Commission,* 576 F.3d 470 at 476–77 (''We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.'').

[393] *MISO Transmission Owners,* 373 F.3d 1361 at 1371.

[394] The Commission has described the phenomenon of parallel path flow as follows: ''In general, utilities transact with one another based on a contract path concept. For pricing purposes, parties assume that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. However, in reality power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths and divide itself along the lines of least resistance. This parallel path flow is sometimes called 'loop flow.' '' *Indiana Michigan Power Co. and Ohio Power Co.,* 64 FERC ¶ 61,184, at 62,545 (1993).

[395] *See, e.g., Amer. Elec. Power Svc. Corp.,* 49 FERC ¶ 61,377, at 62,381 (1989) (*AEP*).

[396] *Id.; see also Southern California Edison Co.,* 70 FERC ¶ 61,087, at 61,241–42 (1995).

[397] *Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168, at P 60 (2004) (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 106 FERC ¶ 61,251, at P 56–57 (2004)). The Commission noted that MISO and PJM had committed in a Joint Operating Agreement to develop such a method for allocating the costs of certain facilities through their joint regional planning committee. *Id.* The Commission did not base the above-noted directive on the existence of the Joint Operating Agreement, which MISO and PJM developed to comply with a previous Commission directive. *See Alliance Cos.,* 100 FERC ¶ 61,137, at P 48, 53 (2002).

[398] *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, at P 10 (2005). *See also Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,102 (2009).

[399] *MISO Transmission Owners,* 373 F.3d 1361. The DC Circuit stated that the subject costs ''are primarily MISO's startup expenses—particularly those pertaining to the MISO Security Center—and certain expenses pertaining to the creation and administration of MISO's open access tariff.'' *Id.* at 1369.

[400] *Id.* at 1367.

[401] *E.g.,* Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; and Multiparty Commenters.

[402] 576 F.3d 470 (7th Cir. 2009) (*Illinois Commerce Commission*).

the benefits they receive with respect to their own uses of the regional transmission grid. On the contrary, it explains that allocating costs only to customers located within the corporate boundaries of the utility that owns the transmission facilities will over-allocate costs to such customers and allow other beneficiaries to become free riders. LS Power concludes that the Commission has exclusive jurisdiction over interstate transmission services, and therefore, the authority and the responsibility to define interstate transmission services—here regional transmission services—and to identify the beneficiaries of those services that are responsible for costs incurred by regional transmission providers.

511. Illinois Commerce Commission agrees with the Commission's decision that, when applying the cost causation principle, the Commission may allocate costs of a transmission facility to a beneficiary identified through an appropriate process, such as a Commission-approved transmission planning process, even if that beneficiary has not entered into a voluntary arrangement with a public utility that is seeking to recover the costs of that facility. However, it asserts that the process must take into account the restrictions on allocation to beneficiaries set forth in *Illinois Commerce Commission,* in which cost causers are primary, and beneficiaries may be taken into account only to the extent that, without the developer's expectation of receiving revenues from such a party, the project ''might not have been built, or might have been delayed.'' Illinois Commerce Commission asserts that an unduly discriminatory socialization of costs based on speculation that uncertain future costs will offset the discrimination does not support a finding of just and reasonable rates.[403]

512. A number of commenters agree that a free rider problem exists in transmission development and that the Commission should bring certainty to cost allocation rules to address this concern.[404] NextEra states that any project that provides benefits to entities, other than the sponsoring entity, creates an incentive for an individual beneficiary to defer investment in hopes that others will fund the project's development, and this has led to stalemate and delay. Federal Trade Commission agrees that the lack of rate structures to allocate the costs of needed transmission, and the free rider problem that arises when project beneficiaries seek to shift transmission construction costs onto others, add uncertainty and conflict to the debate over what transmission to build and how to pay for it. Sunflower and Mid-Kansas state that the free rider problem can be an issue regionally, but is likely to prove more intractable for interregional cost allocation. Boundless Energy and Sea Breeze state that cost allocation has to deal with the free rider issue when multiple utilities are involved because then an independent entity with a proposal that provides system benefits across a larger region may find that beneficiaries will not contract for their portion of the benefits.

513. Several commenters argue that it is unlawful for transmission developers to recover costs from entities to which they do not provide service.[405] Some commenters contend that the Commission ignores that privity of contract existed between the entities involved in the cases that it cites to support its proposal[406] and that the Commission's authority under the FPA is premised on a utility having a contractual relationship or a tariff to provide service to its customers.[407] Nebraska Public Power District asserts that the *Mobile-Sierra* cases support this view.[408]

514. Sacramento Municipal Utility District asserts that there is a distinction between allocating costs among a public utility transmission provider's customers without their voluntary agreement (such as the roll-in of the costs of the transmission provider's bulk transmission system) and allocating them to entities that are not the transmission provider's customers. It argues that *AEP* and similar cases[409] do not establish a right to assess costs of facilities to non-customers and that it is a perversion of the statutory scheme to suggest that an entity could build a transmission facility and then claim that because power generated or scheduled by non-customers flowed over the facility, it was entitled to be compensated by them. Southern Companies note that no complaint was filed in response to *AEP,* and the case therefore does not support the idea that allocation of costs to non-customers is lawful. Northern Tier Transmission Group maintains that even if the Commission has authority to permit allocation of costs to an entity that does not take service from the transmission provider that collects the costs, it has not complied with the common law requirements necessary to delegate that authority to transmission providers.

515. Sacramento Municipal Utility District asserts that the cases that the Commission cites dealing with the allocation of costs between RTOs when new facilities in one of their footprints benefits entities in the other's footprint do not apply here.[410] It argues that in those cases, cross-border facility costs were allocated to each RTO as a whole, after which project costs were recovered by the RTO through its own intra-RTO cost allocation. Sacramento Municipal Utility District states that customers in these cases were not being billed for service taken from entities with which those customers had no contract or applicable tariff, but rather were being billed by their own transmission providers.

516. Sacramento Municipal Utility District takes issue with the Commission's reliance on *MISO Transmission Owners* for the proposition that the cost causation principle allows allocation of at least some types of costs to beneficiaries that are not customers of the public utility that is seeking cost recovery. It states that in that case, MISO was the public utility seeking cost recovery, and the costs in question were not levied directly on the entities in question. Instead, the MISO transmission owners—existing customers under the MISO tariff—had challenged whether the cost allocation reflected in their rates was reasonable. Sacramento Municipal Utility District contends that all the court decided was that the Commission had reasonably allocated

[403] In reply, PPL Companies assert that Illinois Commerce Commission overstates *Illinois Commerce Commission,* arguing that the court did not interpret the cost causation principle to require that costs be allocated on a narrow definition of ''cause'' that ignores benefits received by customers.

[404] *E.g.,* Gaelectric North America; Atlantic Grid; Multiparty Commenters; Primary Power; Pennsylvania PUC; NextEra; Federal Trade Commission; Sunflower and Mid-Kansas; Boundless Energy and Sea Breeze; and LS Power.

[405] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Salt River Project; and Sacramento Municipal Utility District.

[406] *E.g.,* Ad Hoc Coalition of Southeastern Utilities (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 144); Salt River Project (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164).

[407] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Salt River; and Nebraska Public Power District.

[408] Nebraska Public Power District (citing *United Gas Pipeline Co.* v. *Mobile Gas Corp.,* 350 U.S. 332 (1955); *FPC* v. *Sierra Pac. Power Co.,* 350 U.S. 348 (1956)).

[409] In addition to *AEP,* Sacramento Municipal Utility District cites *Sierra Pacific Power Co.,* 85 FERC ¶ 61,314 at 62,235 (1998); *Sierra Pacific Power Co.,* 86 FERC ¶ 61,198 at 61,698 (1999); *Vermont Elec. Power Co.,* 44 FERC ¶ 61,098, at 61,275 (1988).

[410] *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084; *Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168; *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194.

MISO's operating costs to the transmission owners based on their use of MISO-controlled transmission facilities to deliver power to entities that were not subject to the MISO tariff and on the benefits that MISO Transmission Owners derived from that delivery.[411]

517. Sacramento Municipal Utility District asserts that the Commission's position on joint rates supports its position that a contractual customer relationship is a precondition for the allocation of transmission costs. It states that the Commission's position is that, absent evidence that two systems were in fact acting as one, the Commission cannot mandate the use of a single joint rate. Sacramento Municipal Utility District argues that if the Commission cannot mandate joint rates when this condition is not met even where a customer takes service from both utilities, it cannot mandate that an entity pay rates charged by a utility with which it has no contractual or tariff-based customer relationship.[412]

518. ColumbiaGrid argues that the Commission cannot use its authority to force customers to pay for additional benefits that go beyond their existing service. It states that a court has held that under section 5 of the Natural Gas Act, the Commission may reject unjust and unreasonable rates and prescribe a new just and reasonable rate, but it may not require distributors to accept or to pay for additional service.[413] ColumbiaGrid maintains that this shows that costs cannot be recovered from entities that are not customers receiving jurisdictional service. ColumbiaGrid argues that *Illinois Commerce Commission* does not support the allocation of costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries, and it maintains that the Commission's reliance on this case to extend the cost causation principle to cover any entity that may be said to benefit from a project is misplaced.

519. Southern Companies argue that while the Proposed Rule acknowledges the fundamental role of cost causation, it proceeds to nullify the ''but for'' element that is intrinsic to any determination of cost causation. Southern Companies argue that the primary beneficiary of a transmission improvement is the customer that made the request that ''causes'' the improvement in question. They argue that the Proposed Rule seems to attack cost causation by concluding that a participant funding approach is not permissible.

520. Several commenters maintain that in their experience, free rider problems do not exist and that such concerns may be speculative.[414] Ad Hoc Coalition of Southeastern Utilities states that cost socialization is not needed to protect against the inequities of free ridership. It interprets the Commission's reference to the free rider problem as referring to the relatively cost-free transmission that may be provided to entities that take advantage of oversized investments made by others.

521. Southern Companies suggest that if any such problems exist, they are a product of local or regional factors that do not require a national solution. E.ON argues that free rider problems do not exist in the context of reliability or public policy transmission projects, and participant funding of such projects does not exacerbate the free rider problem.

522. Some commenters argue that, even if free rider problems exist, they can either be solved without resort to broad cost allocation or are beyond the Commission's authority.[415] Alternatively, Illinois Commerce Commission states that while a free rider problem does exist, it is impossible to solve in practice, and the negative consequences of allocating costs too broadly will be greater than allocating costs more narrowly to cost causers and direct, quantifiable beneficiaries. Dominion similarly asserts that while broad cost allocation may eliminate free ridership, it may result in some entities paying disproportionate costs.

523. Alabama PSC states that it would be improper to require citizens of Alabama to pay for the costs of transmission facilities in other areas of the country where there is high congestion and which are not necessary to provide service in Alabama. It maintains that this violates the principle of cost causation and the requirement that facilities be ''used and useful'' before being incorporated into a consumer's rates. Indianapolis Power & Light argues that it is inconsistent with cost causation principles to subsidize a state's generation decisions (*e.g.,* a state's renewable portfolio standard), and states should not be able to pass the cost of compliance with their requirements on to other jurisdictions. ELCON agrees and states that a claim of generalized system benefits, such as an amorphous reliability improvement, does not justify regionalized charges. Instead, ELCON asserts that there must be a tangible, nontrivial benefit supported by substantial evidence. ELCON also maintains that disallowing export charges or other forms of cost transfer to beneficiaries in other planning regions will result in unjust and discriminatory rates.

524. Coalition for Fair Transmission Policy states that the Commission lacks authority to require consideration of broad public policy benefits that cannot be measured or projected within a transmission providers' planning horizon. It maintains that allowing the allocation of costs that are not required to maintain reliability, relieve congestion, or to meet mandated public policy requirements is beyond the Commission's core mission.

525. Ad Hoc Coalition of Southeastern Utilities states that in the Southeast, only North Carolina has a renewable portfolio standards requirement, and there is no suggestion that a regional mechanism for funding transmission is needed to satisfy this requirement. It thus sees no reason to discontinue providing cost recovery for regional transmission projects from the entities that choose to use them.

526. ColumbiaGrid argues that at least with respect to non-RTO regions (where there are no regional service tariff rates), directing public and non-public utilities to adopt a specific cost allocation method in advance could infringe upon a utility's right to propose rates under section 205 of the FPA.[416] The California ISO maintains that the Commission does not have the authority to compel rate filings in the first instance, and it can require a filing only if it shows that the existing rate does not meet the requirements of section 206.[417]

[411] *See also* Southern Companies and ColumbiaGrid.

[412] Sacramento Municipal Utility District cites to *Ft. Pierce Utilities Comm'n* v. *FERC,* 730 F.2d 778 (DC Cir. 1984) (*Fort Pierce*); *Richmond Power & Light* v. *FERC,* 574 F.2d 610 (DC Cir. 1978) (''purchasers are always free to subscribe to the services of willing utilities at the separate rates''); *Alabama Power Co.* v. *FERC,* 993 F.2d 1557, 1565 (DC Cir. 1993) (affirming order directing joint rate between holding company members who the Commission found were acting as one); *see also Illinois Power Co.,* 95 FERC ¶ 61,183, at 61,644 (2002) (approving single joint rate across Alliant and MISO systems but recognizing that, in the absence of an agreement between these utilities, there would not be a single rate).

[413] ColumbiaGrid cites to *Exxon Mobil Corp.* v. *FERC,* 430 F.3d 1166 (DC Cir. 2005) (*Exxon Mobil Corp.*).

[414] *E.g.,* Southern Companies; California Municipal Utilities; Transmission Agency of Northern California; and Columbia Grid.

[415] *E.g.,* Nebraska Public Power District and Sacramento Municipal Utility District.

[416] ColumbiaGrid bases this claim on *Atlantic City Electric Co.* v. *FERC,* 295 F.3d 1 (DC Cir. 2002) (*Atlantic City*).

[417] Similarly, Northern Tier Transmission Group argues that the Commission must justify, under

California ISO argues that the Commission cannot fulfill this requirement with regard to cost allocation for regional and interregional facilities because there are no existing contracts or rates for such services. The Commission may at most issue guidance on whether future filings will meet statutory requirements.

527. Southern Companies assert that where vertically integrated transmission providers plan their transmission systems from the bottom up under state supervision and recover most of their costs for transmission facilities through bundled rates, the Proposed Rule's mandates cannot be implemented without preempting or undermining state law. Southern Companies state that the Commission should revise its proposed reforms and explain how they can be implemented while respecting existing processes for bundled retail ratemaking. Southern Companies assert that they recover only approximately 15 percent of their transmission revenue requirements under a federal OATT, with the remaining 85 percent being recovered in state-regulated bundled rates. They state that the latter cost recovery is not an issue of federal comparability, and a nonincumbent would, at best, be allowed to recover only 15 percent of its transmission costs under a federal OATT, with the rest requiring state approval. Southern Companies maintain that as a practical matter, a nonincumbent cannot have ''comparable'' cost recovery without a long-term contract from Southern Companies that has appropriate state commission approval for purposes of retail rate recovery.

528. Transmission Access Policy Study Group urges the Commission to address allocation of costs of transmission projects that go beyond existing boundaries of an RTO or individual transmission providers where the transmission grid is integrated. It recommends that the Commission recognize that it has the authority to order joint, non-pancaked rates where transmission systems are integrated. Sacramento Municipal Utility District argues in response that the Commission cannot require joint rates unless two adjoining transmission systems are not just integrated, but effectively operate as a single system. Large Public Power Council agrees. Ad Hoc Coalition of Southeastern Utilities argues that the statutory right of utilities to set their rates may not be easily set aside, and that imposing a joint, non-pancaked rate structure on utilities would do exactly that.

529. Florida PSC is concerned that the Commission's proposal may circumvent its authority over rates for transmission infrastructure that serves retail load because the Proposed Rule appears to allow entities seeking to construct merchant transmission projects to recover project costs from Florida ratepayers through a Commission-approved cost allocation process. North Carolina Agencies argue that the Final Rule should recognize the indispensible role of state regulatory authorities and should apply only to unbundled transmission rates. Northwestern Corporation (Montana) states that entities seeking to recover costs without approval from state public utilities commissions face the risk of cost disallowance.

3. Commission Determination

530. We conclude that we have the legal authority to adopt the cost allocation reforms required by this Final Rule. Numerous commenters challenge our authority to require allocation of transmission costs to beneficiaries that do not have a contractual or formalized customer relationship with the entity that is collecting the costs. These challenges are based primarily on the commenters' analysis of various Commission and court cases. Some commenters have made arguments that speak directly to provisions of the FPA, but none of these assertions reach convincing conclusions. For instance, Ad Hoc Coalition of Southeastern Utilities states that ''[u]tilities filing for rate changes under FPA section 205 ask the Commission to approve changes in rates charged *to their customers*'' and that ''the Commission's authority is, in all cases, based on the premise that a utility has a contractual relationship to provide service to its customers.'' [418] However, section 205 does not specify any such limitation and no commenter has shown where it is expressed elsewhere in the FPA. Instead, commenters generally appear to agree with Ad Hoc Coalition of Southeastern Utilities that the ''FPA is structured on the *assumption* that rates subject to [Commission] approval are supported by a contractual agreement.'' [419]

531. The merit of this argument depends, of course, on how the FPA is in fact structured, and an examination of the relevant provisions of the statute shows that it is not structured in a way that would justify this argument. On the contrary, the Commission's jurisdiction is clearly broad enough to allow it to ensure that all beneficiaries of services provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities. As discussed further below, this comports fully with the specific characteristics of transmission facilities and transmission services, and our actions today are necessary to fulfill our statutory duty of ensuring rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. We thus turn first to the language of the statute itself.

532. Section 201(b)(1) of the FPA gives the Commission jurisdiction over ''the transmission of electric energy in interstate commerce.'' The Commission's jurisdiction therefore extends to the rates, terms and conditions of transmission service, rather than merely transactions for such transmission service specified in individual agreements. Moreover, section 201(b)(1) gives the Commission jurisdiction over ''all facilities'' for the transmission of electric energy, and this jurisdiction is not limited to the use of those transmission facilities within a certain class of transactions. As a result, the Commission has jurisdiction over the use of these transmission facilities in the provision of transmission service, which includes consideration of the benefits that any beneficiaries derive from those transmission facilities in electric service regardless of the specific contractual relationship that the beneficiaries may have with the owner or operator of these transmission facilities.

533. Neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. These statutory provisions speak of rates and charges that are ''made,'' ''demanded,'' ''received,'' ''observed,'' ''charged,'' or ''collected'' by a public utility. Any such rates or charges must, of course, be accepted for filing with the Commission under either section 205 or 206, but nothing in these sections precludes flows of funds to public utility transmission providers through mechanisms other than agreements between the service provider and the beneficiaries of those transmission facilities.

534. Transmission services create an opportunity for free ridership because the nature of power flows over an interconnected transmission system does not permit a public utility

section 206, modifying the cost allocation process that it already accepted for its members.

[418] Ad Hoc Coalition of Southeastern Utilities Comments at 60–61 (emphasis in original).

[419] *Id.* at 60 (emphasis supplied).

transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them. The Commission expressed concern over free ridership in Order No. 890, where it noted that ''there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it.'' [420]

535. In Order No. 890, the Commission recognized that the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them. We conclude now that this principle cannot be limited to voluntary arrangements because if it were ''the Commission could not address free rider problems associated with new transmission investment, and it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory. In fact, the courts have recognized this aspect of cost causation quite independently of an analysis of the scope of our statutory jurisdiction over transmission.

536. The courts have acknowledged that cost causation involves ''comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' [421] An approach to cost causation that is limited to voluntary arrangements such as participant funding has the effect of ''focusing us on the most immediate and proximate cause of the cost incurred,'' and it precludes looking ''at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign[ing] them liability too.'' [422] In short, a full cost causation analysis may involve ''an extension of the chain of causation'' [423] beyond those causes captured in voluntary arrangements. In other words, to identify all causes, we must to some degree begin with their effects, *i.e.,* the benefits that they engender and then work back to their sources.

537. This point was acknowledged in the Seventh Circuit's characterization of cost causation in *Illinois Commerce Commission.* The Seventh Circuit states that:

> To the extent that a utility benefits from the costs of new facilities, *it may be said to have ''caused'' a part of those costs to be incurred,* as without the expectation of its contributions the facilities might not have been built, or might have been delayed.[424]

The court fully recognized that, to identify causes of costs, one must to some degree begin with benefits. ColumbiaGrid argues that *Illinois Commerce Commission* does not support the Commission's position on cost allocation because the statement just cited is preceded by the statement that ''[A]ll *approved* rates [must] reflect to some degree the costs actually caused by the customer who must pay them.'' [425] ColumbiaGrid maintains that this demonstrates the *Illinois Commerce Commission* ''does not support the [Proposed Rule's] approach of allocating costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries.'' [426] What this argument fails to recognize is that the point ColumbiaGrid contests was not before the court in *Illinois Commerce Commission,* and the Commission's jurisdiction over transmission, as outlined above, is broad enough to approve rates based on the court's characterization of cost causation.[427] In other words, there is nothing in what the court said that can be viewed as preventing the Commission from dealing with the free rider problem. Indeed, by emphasizing the relationship between beneficiaries identified and cost allocation, the court's ruling supports greater attention to that issue. Finally, we note that under this Final Rule, transmission planning regions are not required to analyze the distribution of benefits on an entity-by-entity basis; nothing in this Final Rule precludes the regions from doing so, provided that they satisfy the cost allocation principles adopted herein. We now turn to other individual comments that involve these issues.

538. Southern Companies' argument that the primary beneficiary of a transmission facility is the customer that made the request that causes the improvements to be planned and constructed tends to blur the distinction between benefits and burdens. As discussed above, the courts have acknowledged that distinction as relevant to cost allocation and the requirements in this Final Rule are consistent with that distinction. To the extent that commenters are supporting participant funding as a regional cost allocation method, we address those comments below.[428]

539. We disagree with Sacramento Municipal Utility District and Southern Companies that *AEP* applies only in exceptional circumstances and does not support our position here. In that case, the Commission expressed a preference for a voluntary resolution of the problem that loop flow represented, a position that is consistent with our findings here. The Commission's authority is not limited in principle by cases where the Commission expresses a preference not to exercise that authority. We also disagree with Sacramento Municipal Utility District that our reforms represent a perversion of the statutory scheme in which an entity could build a transmission facility and then simply claim a right to payment for benefits from beneficiaries with which it has no contractual or tariff relationship. As we state above, the Commission's jurisdiction is broad enough to allow it to ensure that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities. Our cost allocation reforms are tied to our transmission planning reforms, which require that, to be eligible for regional cost allocation, a proposed new transmission facility first must be selected in a regional transmission plan for purposes of cost allocation, which depends on a full assessment by a broad range of regional stakeholders of the benefits accruing from transmission facilities planned according to the reformed transmission planning processes. As such, the public utility transmission providers in the regional

[420] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 561.

[421] *MISO Transmission Owners,* 373 F.3d 1361, at 1368 (internal citations omitted).

[422] *KN Energy,* 968 F.2d 1295 at 1302.

[423] *Id.*

[424] *Illinois Commerce Commission,* 576 F.3d 470 at 476 (emphasis supplied).

[425] ColumbiaGrid Comments at 29 (citing *Illinois Commerce Commission,* 576 F.3d 470 at 476 (emphasis supplied by ColumbiaGrid)).

[426] *Id.*

[427] This point applies equally to Sacramento Municipal Utility District's objection that the other Commission and court cases pertaining to MISO cited in the Proposed Rule are not on point because they involve instances where a customer relationship of some type had already been established, and that all that these cases dealt with was whether an allocation was just and reasonable. When Sacramento Municipal Utility District states that ''the cost allocation methods approved by FERC in the MISO cases rested on the understanding that 'the ultimate costs allocated to [MISO] or PJM for a so-called cross-border allocation project will be recovered by each RTO pursuant to the applicable provisions of their tariffs,' '' it is ignoring substance in favor of form. It is focusing on the formal mechanisms through which costs are collected, not the underlying substance of the cost allocation itself. *See* Sacramento Municipal Utility District Comments at 14 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194 at P 4). The mechanism for recovering a rate does not change the identity of the provider who is in fact recovering it.

[428] *See* discussion *infra* section IV.F.2.

transmission planning process identify the beneficiaries who will pay for the costs of the new transmission facility selected in a regional plan for purposes of cost allocation.

540. The fact that the Commission has supported parts of its argument through reference to cases in which privity of contract existed between public utilities and the entities from which costs were recovered does not affect this conclusion.[429] This issue was not before the court in any of these cases, and therefore the mere existence of privity of contract does not demonstrate the necessity of privity. In response to Nebraska Public Power District, we do not agree that the *Mobile-Sierra* doctrine has applicability here. We are dealing here with conditions under which costs can be recovered in rates, not conditions under which existing contracts rates can be altered.

541. Contrary to ColumbiaGrid's position, *Exxon Mobil Corp.* does not apply here. As ColumbiaGrid states, in *Exxon Mobil Corp.* the court held that the Commission may not require distributors to accept or pay for additional service.[430] Unlike the situation addressed in *Exxon Mobil Corp.,* the requirements of this Final Rule with respect to cost allocation do not ''impose'' any new service on beneficiaries.

542. We also note that our position on joint rates does not have any relevance here. The fact that the Commission cannot require two public utilities to charge a joint rate without evidence that their two systems are in fact acting as one does not preclude the Commission from permitting a single public utility to recover its costs from beneficiaries of the transmission facilities identified in the transmission planning process regardless of the formal customer relationships that exist prior to the time that cost allocation is authorized. We do not see how the conditions under which a joint rate can be imposed has any implications for the range of beneficiaries from which a single public utility can recover the costs of its transmission services, even when combined with recovery by other public utilities of related transmission facilities.

543. We disagree with Northern Tier Transmission Group that we are delegating any authority to transmission providers. All proposed cost allocation methods will be subject to Commission approval, and all specific allocations will be incorporated in rates that must be filed with and accepted by the Commission.

544. We agree with the Alabama PSC that citizens of Alabama should not be responsible for costs of transmission facilities from which they derive no benefits. Indeed, the Commission specified in the Proposed Rule as a principle of regional cost allocation that ''[t]hose that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.'' [431] With respect to interregional transmission coordination, the Commission specified that a ''transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility.'' [432] In addition, ''[c]osts cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located.'' [433] These cost allocation principles are adopted in this Final Rule, and its requirements thus conform fully with the position taken by the Alabama PSC.

545. Contrary to the claims of Indianapolis Power & Light, the reforms instituted in this Final Rule neither authorize nor will lead to subsidization of generation decisions by different states. Beneficiaries in one state are not subsidizing anyone in another state when they are allocated costs that are commensurate with the benefits that accrue to them, even if the transmission facility in question was built in whole or part as a result of the other state's transmission needs driven by Public Policy Requirements. If no benefits accrue, the cost allocation principles we adopt below would prohibit the allocation of costs to the non-beneficiaries. If benefits do accrue, however, there are no less benefits because Public Policy Requirements played a role in the decision to construct the transmission facility. We agree with ELCON that estimations of benefits require adequate support. We note, however, that benefits are not ''amorphous'' simply because costs are to be allocated ''in a manner that is roughly commensurate with estimated benefits.'' [434] The courts have acknowledged the natural limits that accompany estimations made in the cost-allocation process.[435]

546. We disagree with Coalition for Fair Transmission Policy that the Proposed Rule can be read to imply that the Commission may require consideration of broad policy goals that are far afield from the Commission's core mission. This Final Rule requires that public utility transmission providers establish a process for identifying those transmission needs driven by Public Policy Requirements that are to be considered in the transmission planning process.[436] In doing this, we are simply acknowledging that such Public Policy Requirements are facts that may have consequences in the form of increasing or decreasing the demand for additional transmission facilities. We are not straying from our core mission when we acknowledge that these facts will affect matters that are central to that mission and accordingly require that they be considered in the transmission planning process, nor are we promoting any particular public policy by requiring a process to determine what, if any, transmission needs are driven by a Public Policy Requirement.[437]

547. Directing a public utility transmission provider to adopt a specific cost allocation method or methods in advance does not infringe upon a utility's right to propose rates under section 205 of the FPA. It simply requires that rate filings meet certain standards. ColumbiaGrid cites *Atlantic City* as supporting the contrary position. In that case, the court held that the Commission could not require that the PJM Transmission Owners Agreement be modified to eliminate a provision that allowed a public utility transmission owner to make a unilateral filing to make changes in rate design or terms and conditions of jurisdictional services. The court held that public utilities have an express right under section 205 to make such filings, and the Commission could not require them to relinquish it.[438] Nothing in this Final Rule has the effect of disenfranchising any individual or entity of rights under

[429] *See Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168; *Alliance Cos.,* 100 FERC ¶ 61,137.

[430] *See Exxon Mobil Corp.,* 430 F.3d 1166, 1176–77 (DC Cir. 2005).

[431] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164.

[432] *Id.* P 174.

[433] *Id.*

[434] The Commission discusses in detail the application of this cost allocation principle below.

[435] *Illinois Commerce Commission,* 576 F.3d 470 at 476–77 (''We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.''). *See also MISO Transmission Owners,* 373 F.3d 1361 at 1369 (''we have never required a ratemaking agency to allocate costs with exacting precision.''); *Sithe,* 285 F.3d 1 at 5.

[436] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 4.

[437] *See* discussion *supra* section III.A.4.

[438] *Atlantic City,* 295 F.3d 16, at 21 (DC Cir. 2002).

section 205 to make filings. The Commission regularly establishes standards for filings under section 205, and doing so does not negate any rights under that section.

548. In response to those commenters that argue that our cost allocation reforms will affect existing state jurisdiction over utility rates, it is not clear why cost allocations consistent with this Final Rule would affect state jurisdiction differently from existing cost allocations. In any event, we find that such arguments are premature. It is inappropriate for the Commission to decide such issues generically in a rulemaking, as such issues should be decided based on specific facts and circumstances, none of which are presented here.

549. In response to Transmission Access Policy Study Group, we note that the issue of joint rates is beyond the scope of this proceeding. This Final Rule requires the development of cost allocation methods for regional and interregional transmission facilities in connection with its planning reforms. As described in the cases that commenters cite in their responses to Transmission Access Policy Study Group, the issue of joint, non-pancaked rates involves matters that are considerably broader than our transmission planning-based cost allocation reforms. The Commission will consider any calls for joint, non-pancaked rates on a case-by-case basis and in accordance with the principles established in these cases.

C. Cost Allocation Method for Regional Transmission Facilities

1. Commission Proposal

550. The Proposed Rule would require that every public utility transmission provider develop a method, or set of methods, for allocating the costs of new transmission facilities that are included in the transmission plan produced by the transmission planning process in which it participates. If the public utility transmission provider is an RTO or ISO, then the method or methods would be required to be set forth in the RTO or ISO tariff. In other transmission planning regions, each public utility transmission provider would be required to set forth in its tariff the method or methods for cost allocation used in its transmission planning region. This method or methods would have to satisfy six regional cost allocation principles, discussed below.

551. These regional cost allocation principles would apply only to the cost allocation method or methods for new transmission facilities selected in the regional transmission plan produced by the transmission planning process in which the public utility transmission provider participates. The Commission also stated that it did not intend to require a uniform cost allocation method that every region must adopt to allocate the costs of new regional transmission facilities that are eligible for cost allocation, but instead recognized that regional differences may warrant distinctions in cost allocation methods among transmission planning regions.[439]

552. The Commission stated in the Proposed Rule that with regard to a new transmission facility that is located entirely within one transmission owner's service territory, a transmission owner may not unilaterally invoke the regional cost allocation method to require the allocation of the costs of a new transmission facility to other entities in its transmission planning region. However, if the regional transmission planning process determines that a new facility located solely within a transmission owner's service territory would provide benefits to others in the region, allocating the facility's costs according to that region's regional cost allocation method or methods would be permitted.[440]

2. Comments on Cost Allocation Method in Regional Transmission Planning

553. A number of commenters generally support the Commission's proposal.[441] For example, ITC Companies support the promulgation of a comprehensive, holistic cost allocation method generally applicable to new transmission facilities, citing SPP's highway/byway mechanism as a model.[442]

554. Other commenters express concern with the Commission's proposal to require the development of a cost allocation method for transmission facilities included in a regional transmission plan.[443] Bonneville Power asserts that mandatory regional cost allocation is not necessary to build new transmission in the Pacific Northwest, and such a requirement will lead to extended disputes and greater uncertainty. Bonneville Power contends that instead, voluntary participation, including participation in open seasons, is the best way to encourage the development of new transmission for renewables in the Pacific Northwest. California Commissions echo the sentiment that cost allocation has generally not been a major barrier to entry for new transmission in the West. California Commissions are concerned that the Commission may do more harm than good by moving aggressively and prescriptively on regional cost allocation methods that are not necessarily needed to support transmission development.

555. Some commenters, such as Bonneville Power, California ISO, and Western Area Power Administration, express a preference for voluntary coordination and cost allocation of transmission facilities rather than mandatory cost allocation rules. Coalition for Fair Transmission Policy urges the Commission to consider whether it is prudent in all cases to require the filing of regional cost allocation methods by transmission providers in advance of projects being proposed, as not every project will fit into a particular model, and adherence to strict rules may deter rather than encourage the construction of needed new transmission facilities.

556. New York PSC indicates that it is uncertain as to whether the Commission intends to utilize a pre-established cost allocation methodology as an automatic right of cost recovery. Therefore, New York PSC requests that the Commission clearly indicate when a project would be entitled to cost recovery relative to receiving a cost allocation. Western Grid Group shares the view that the distinction between cost allocation and cost recovery is a pertinent issue. Arizona Public Service Company raises concerns about cost recovery in regions where no regional tariff mechanisms exist. In the absence of such a cost recovery solution, Arizona Public Service Company states that the Commission should not place the burden of recovery for third party developers on incumbent utilities that may be required to seek such recovery

[439] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 165.

[440] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 169.

[441] *E.g.,* MidAmerican; American Transmission; Clean Line; Dominion; East Texas Cooperatives; MISO; National Grid; NEPOOL; New York ISO; Multiparty Commenters; and WIRES.

[442] The arguments in support of this proposal are implicit in the comment summaries under the discussion of other cost allocation proposals below. *See* discussion *infra* section 0. The term ''highway/byway'' refers to regionwide allocation of the cost of a new high voltage transmission facility and the allocation of the cost of a new lower voltage transmission facility to a defined portion of the region. *See Southwest Power Pool, Inc.,* 131 FERC ¶ 61,252 (2010).

[443] *E.g.,* Bonneville Power Administration; California Commissions; Eastern Massachusetts Consumer-Owned System; Xcel; and Western Area Power Administration.

through state commissions for facilities that the incumbent utilities have not built and for which the incumbent utilities may be unable to show benefit for their ratepayers.

557. MISO Transmission Owners agree that a transmission provider should not be able to invoke the regional cost allocation method unilaterally for a facility located entirely within its own service territory. However, they state that in the RTO context, facilities located solely within one transmission owner's service territory should be allocated in accordance with the Commission-accepted cost allocation method. MISO Transmission Owners state that the Proposed Rule should not be interpreted to indicate that single-zone facilities are no longer eligible for regional cost allocation if such allocation is permitted under an RTO or ISO tariff. Additionally, MISO Transmission Owners argue that the Commission should not permit this requirement to allow attempts to relitigate existing cost allocation method that apply to intra-zonal transmission facilities.

3. Commission Determination

558. We require that a public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. If the public utility transmission provider is an RTO or ISO, then the cost allocation method or methods must be set forth in the RTO or ISO OATT. In a non-RTO/ISO transmission planning region, each public utility transmission provider located within the region must set forth in its OATT the same language regarding the cost allocation method or methods used in its transmission planning region. In either instance, such cost allocation method or methods must be consistent with the regional cost allocation principles adopted below.

559. We conclude that these regional transmission cost allocation requirements are necessary to ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. In the absence of clear cost allocation rules for regional transmission facilities, there is a greater potential that public utility transmission providers and nonincumbent transmission developers may be unable to develop transmission facilities that are determined by the region to meet their needs. Conversely, greater certainty as to the cost allocation implications of a potential transmission project will enhance the ability of stakeholders in the regional transmission planning process to evaluate the merits of the transmission project. Moreover, as we have established above, there is a fundamental link between cost allocation and planning, as it is through the planning process that benefits, which are central to cost allocation, can be assessed.

560. We do not specify here how the costs of an individual regional transmission facility should be allocated. However, while each transmission planning region may develop a method or methods for different types of transmission projects, such method or methods should apply to all transmission facilities of the type in question. Although we allow a different method or methods for different types of transmission facilities, as discussed below regarding regional Cost Allocation Principle 6, if public utility transmission providers choose to propose a different cost allocation method or methods for different types of transmission facilities, each method would have to be determined in advance for each type of facility.

561. We disagree with California Commissions that our actions here are too aggressive and prescriptive and with Bonneville Power that adopting a mandatory cost allocation method will lead to extended disputes and greater uncertainty. We have stressed throughout this proceeding that we intend to be flexible and are open to a variety of approaches to compliance. By imposing the cost allocation requirements adopted here, the Commission seeks to enhance certainty for developers of potential transmission facilities by identifying, up front, the cost allocation implications of selecting a transmission facility in the regional transmission plan for purposes of cost allocation. This does not undermine the ability of market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or methods. Indeed, market participants may be in a better position to undertake such negotiations as a result of the public utility transmission providers in the region having evaluated a transmission project. The results of that evaluation, including the identification of potential beneficiaries of the transmission project, could facilitate negotiations among potentially interested parties.

562. In response to Coalition for Fair Transmission Policy, we require the development of a cost allocation method or a set of methods in advance of particular transmission facilities being proposed so that developers have greater certainty about cost allocation and other stakeholders will understand the cost impacts of the transmission facilities proposed for cost allocation in transmission planning. The appropriate place for this consideration is the regional transmission planning process because addressing these issues through the regional transmission planning process will increase the likelihood that transmission facilities selected in regional transmission plans for purposes of cost allocation are actually constructed, rather than later encountering cost allocation disputes that prevent their construction.

563. With regard to comments regarding matters of cost recovery, we acknowledge that cost allocation and cost recovery are distinct. This Final Rule sets forth the Commission's requirements regarding the development of regional and interregional cost allocation methods and does not address matters of cost recovery. We disagree with Arizona Public Service Company, however that incumbent utilities may be unreasonably burdened by the potential of cost allocation for transmission facilities developed by third party developers. For any proponent of a transmission facility, whether an incumbent or a nonincumbent, to have the costs of a transmission facility allocated through the regional cost allocation method or methods, its transmission facility first must be selected in the regional transmission plan for purposes of cost allocation. This in turn requires a determination that the transmission project is an efficient or cost-effective solution pursuant to the processes the transmission providers in the region have put in place, including consultation with stakeholders. Therefore, the benefits of any such transmission project should have been clearly identified prior to the allocation of any related costs.

564. With respect to cost allocation for a proposed transmission facility located entirely within one public utility transmission owner's service territory, we find that a public utility transmission owner may not unilaterally apply the regional cost allocation method or methods developed pursuant to this Final Rule. However, a proposed transmission facility located entirely within a public utility transmission owner's service territory could be determined by public utility transmission providers in the region to provide benefits to others in the region and thus the cost of that transmission facility could be allocated according to

that region's regional cost allocation method or methods.

565. In response to MISO Transmission Owners' concerns regarding relitigation of existing Commission-approved transmission cost allocation methods, the Commission declines here to prejudge whether any such existing cost allocation methods comply with the requirements of this Final Rule. To the extent MISO Transmission Owners believe that to be the case with their region, they may take such positions during the development of compliance proposals and during Commission review of compliance filings. However, we reiterate here that our cost allocation reforms apply only to new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation and, therefore, do not provide grounds for relitigation of cost allocation decisions for existing transmission facilities.

D. Cost Allocation Method for Interregional Transmission Facilities

1. Commission Proposal

566. The Proposed Rule would require that each public utility transmission provider within a transmission planning region develop a method for allocating the costs of a new interregional transmission facility between the two neighboring transmission planning regions in which the facility is located or among the beneficiaries in the two neighboring transmission planning regions. This common method would have to satisfy six interregional cost allocation principles, discussed below.

567. The Commission stated in the Proposed Rule that it would not apply the interregional cost allocation principles so as to require every pair of regions to adopt the same uniform approach to cost allocation for new interregional transmission facilities, but instead recognized that there may be legitimate reasons for the public utility transmission providers located in different pairs of neighboring transmission planning regions to adopt different cost allocation methods.[444]

2. Comments on Interregional Cost Allocation Reforms

568. A number of commenters generally support the proposal that each transmission provider have an interregional cost allocation method for facilities located in more than one region.[445] NEPOOL states that it generally supports the proposal to require formal agreements between neighboring control areas that contain cost allocation methods for interregional projects, with such methods being subject to the principles specified in the Proposed Rule. East Texas Cooperatives support the application of the six proposed principles to interregional cost allocation methods. AEP states that getting these ground rules in place is essential to move forward on major interregional projects and to break down decades old barriers to these types of projects. Likewise, MidAmerican states that there is little if any coordination of transmission cost allocation between MISO and SPP regions and the MISO and MAPP regions and, as such, supports the Commission's efforts to create a more coordinated and effective way to allocate costs of new transmission facilities both within these planning regions and those linking adjacent planning regions.

569. Vermont Electric states that it welcomes the proposed requirement for interregional coordination and the Commission's attention to what it views as deficiencies in the ISO New England transmission planning process. Vermont Electric states that the Commission's proposed requirement for a standard cost allocation method applicable to interregional projects would prevent delays, reduce costs for project developers, and facilitate development of potentially valuable interregional projects.

570. A number of commenters question or express concern about the appropriateness of requiring the development of interregional cost allocation methods for future interregional transmission facilities in advance of a proposal for a specific interregional facility.[446] For example, SoCal Edison notes that voluntary coordination efforts are underway, and it argues that there is no reason to impose additional mandatory interregional coordination criteria or requirements. ISO New England supports the preservation of a voluntary, flexible approach to interregional cost allocation that recognizes regional differences. ISO New England also states that the Final Rule should either clarify the manner in which agreement on cost allocation would be signified by each of the two regions or provide for flexibility in recognition of the mechanisms that may be most appropriate in light of the internal transmission planning processes of the paired regions.

571. National Grid believes that interregional coordination agreements should include general cost allocation principles that will apply to interregional projects, but that it would not be beneficial to prescribe an interregional cost allocation method in advance of a specific interregional project. Similarly, New England Transmission Owners and New York Transmission Owners contend that, in light of the limited number of projects that are likely to be identified through interregional coordination, the Commission should allow cost allocation issues to be decided in connection with individual projects instead of dictating a generic cost allocation method in advance.

572. Vermont Electric agrees, suggesting that the Commission impose an interregional requirement only to the extent regional planning organizations do not respond promptly and effectively to cost allocation issues applicable to interregional projects on a case-by-case basis. New York ISO recommends that the Commission require neighboring regions to include language in their tariffs setting forth their obligation to negotiate cost allocation rules for any interregional projects that are approved in their respective planning processes and that such rules must comply with the cost allocation principles established in the Final Rule.

573. Similarly, Transmission Agency of Northern California cautions against requiring the development of cost allocation principles between planning regions prior to the need for such coordination. California ISO and Indianapolis Power & Light also argue that the requirement for a mandatory advanced agreement on cost allocation before knowing the specific facts and circumstances of an interregional project is neither appropriate nor effective. Indianapolis Power & Light also states that it would be better to postpone development of such agreements until a specific interregional project has been proposed.

574. California ISO states that the Commission should not mandate an interregional cost allocation method or methods because the existing case-by-case determination of cost allocation for interregional transmission facilities has worked well in the West. California ISO states that different parties will bring different interests to the table, and different circumstances may warrant different approaches to interregional cost allocation. However, California ISO states that regardless of what the

[444] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 175.

[445] *E.g.,* AEP; Clean Line; MidAmerican; MISO; MISO Transmission Owners; NEPOOL; New England States Committee on Electricity; Northeast Utilities; Pennsylvania PUC; PSEG Companies; and Energy Consulting Group.

[446] *E.g.,* New York ISO; Coalition for Fair Transmission Policy; California ISO; and National Grid.

Commission concludes on this issue, it should retain in the Final Rule the concept that inclusion of an interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to applying an interregional cost allocation principle.[447] California ISO argues that this is necessary to ensure equitable cost allocation.

575. Edison Electric Institute states that flexibility is especially important for multistate projects with a large number of likely beneficiaries. It states that flexibility also is important for different regions in developing interregional cost allocation methods, including methods that provide for a case-by-case evaluation of projects in lieu of using prescribed cost allocation formulas. Edison Electric Institute states that the Commission should allow a region to propose the evaluation of alternative cost-effective projects that would result in lower costs to the region's consumers.

576. Edison Electric Institute also asks the Commission to be clear in the Final Rule about whether and how existing interregional cost allocation mechanisms and those under development in various regions will be affected, if at all. Transmission Dependent Utility Systems and Xcel support the proposed requirement, but request that the Commission not disrupt or disturb the methods already in place. New England Transmission Owners state that the Commission should permit New England and New York to move forward to develop coordinated interregional coordination based on the principles in their current agreement.

577. SPP seeks clarification, consistent with Order No. 890, that transmission owning members of RTOs and ISOs can comply with the proposed interregional cost allocation mandates through their participation in the RTO or ISO and the interregional agreements executed by the RTO or ISO, rather than requiring them to negotiate with their neighbors to develop separate arrangements.

3. Commission Determination

578. We require a public utility transmission provider in a transmission planning region to have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located.[448] As we discuss further below, the cost allocation method or methods used by the pair of neighboring transmission regions can differ from the cost allocation method or methods used by each region to allocate the cost of a new interregional transmission facility within that region. For example, region A and region B could have a cost allocation method for the allocation of the costs of an interregional transmission facility between regions A and B (the interregional cost allocation method) that could differ from the respective regional cost allocation method that either region A or region B uses to further allocate its share of the costs of an interregional transmission facility. In an RTO or ISO region, the method must be filed in the OATT. In a non-RTO/ISO transmission planning region, the common cost allocation method or methods must be filed in the OATT of each public utility transmission provider in the transmission planning region. In either instance, such cost allocation method or methods must be consistent with the interregional cost allocation principles adopted below.

579. As with our regional cost allocation requirements above, we are requiring interregional cost allocation requirements to remove impediments to the development of transmission facilities that are identified as needed by the relevant regions. We conclude that the absence of clear cost allocation rules for interregional transmission facilities can impede the development of such transmission facilities due to the uncertainty regarding the allocation of responsibility for associated costs. This may, in turn, adversely affect rates for jurisdictional services, causing them to become unjust and unreasonable or unduly discriminatory or preferential.

580. As in the case of regional cost allocation, we do not require a single nationwide approach to interregional cost allocation but instead allow each pair of neighboring regions the flexibility to develop its own cost allocation method or methods consistent with the interregional cost allocation principles adopted in this Final Rule. We also clarify that we do not require each transmission planning region to have the same interregional cost allocation method or methods with each of its neighbors. Each pair of transmission planning regions may develop its own approach to interregional cost allocation that satisfies both transmission planning regions' needs and concerns, as long as that approach satisfies the interregional cost allocation principles. Our intention is to preserve the ability of each pair of transmission planning regions to plan for future development of interregional transmission projects that will be beneficial to both transmission planning regions.

581. We do not specify here how the costs for an individual interregional transmission facility should be allocated. However, while transmission planning regions can develop a different cost allocation method or methods for different types of transmission projects, such a cost allocation method or methods should apply to all transmission facilities of the type in question. Although we allow a different cost allocation method or methods for different types of transmission facilities, as discussed below regarding Interregional Cost Allocation Principle 6, if public utility transmission providers choose to propose a different cost allocation method or methods for different types of transmission facilities, each cost allocation method would have to be determined in advance for each type of transmission facility. Also, we adopt the requirement that an interregional transmission facility must be in the relevant regional transmission plans to be eligible for interregional cost allocation pursuant to the interregional cost allocation method or methods.

582. Additionally, a central underpinning to our reforms in this Final Rule is the closer alignment of transmission planning and cost allocation. As we discuss above in the section on interregional transmission coordination,[449] an interregional transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to a cost allocation method required under this Final Rule. This is designed, among other things, to allow for adequate stakeholder review of the interregional transmission facility before the relevant portion of the facility is in a regional transmission plan.[450] This process could be undermined if a transmission facility that is located and

[447] *See also, e.g.,* Connecticut & Rhode Island Commissions.

[448] A group of three or more transmission planning regions within an interconnection—or all of the transmission planning regions within an interconnection—may agree on and file a common method or methods for allocating the costs of a new interregional transmission facility. However, the Commission does not require such multiregional provisions among more than two neighboring transmission planning regions.

[449] *See* discussion *supra* section III.C.

[450] *See* discussion *supra* section III.C.

reviewed only within one regional transmission planning process, could nevertheless have its costs allocated to potential beneficiaries in another region that may not have had an adequate opportunity to review the need for the transmission facility and make the resulting beneficiary determinations. As we make clear in our discussion of Cost Allocation Principle 4,[451] costs may be assigned on a voluntary basis under this Final Rule to a transmission planning region in which an interregional transmission facility is not located. Given this option, regions are free to negotiate interregional transmission arrangements that allow for the allocation of costs to beneficiaries that are not located in the same transmission planning region as any given interregional transmission facility.

583. With respect to existing interregional transmission coordination and cost allocation agreements, we do not opine here on whether such agreements satisfy the interregional transmission coordination requirements and cost allocation principles of this Final Rule.[452] To the extent that a public utility transmission provider believes such an agreement satisfies these requirements in whole or in part, that public utility transmission provider should describe in its compliance filing how the relevant requirements are satisfied by reference to tariff sheets on file with the Commission.

584. We also clarify in response to commenters that the requirement to coordinate with neighboring regions applies to public utility transmission providers within a region as a group, not members within an RTO or ISO acting individually. Therefore, within an RTO or ISO, the RTO or ISO would develop an interregional cost allocation method or methods with its neighbors on behalf of its public utility transmission owning members.

E. Principles for Regional and Interregional Cost Allocation

1. Use of a Principles-Based Approach

a. Commission Proposal

585. For the cost allocation method or methods to be just and reasonable and not unduly discriminatory or preferential, the Proposed Rule would require that each cost allocation method satisfy six general cost allocation principles, as set out in the following subsections. The Commission proposed six regional cost allocation principles for each cost allocation method for regional transmission facilities included in the regional transmission plan for purposes of cost allocation and six analogous interregional cost allocation principles for each cost allocation method for a new transmission facility that is located in two neighboring transmission planning regions and is accounted for in the interregional transmission coordination process.

586. Specifically, the Proposed Rule would require that each RTO or ISO (on behalf of its transmission owning members) or the individual public utility transmission providers in a non-RTO/ISO transmission planning region to demonstrate through a compliance filing that its cost allocation method or methods for new transmission facilities satisfy the following regional cost allocation principles:

(1) The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.[453] In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.[454]

(2) Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.

(3) If a benefit to cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional transmission plan for the purpose of cost allocation, it must not be so high that facilities with significant positive net benefits are excluded from cost allocation. A transmission planning region or public utility transmission provider may want to choose such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio.

(4) The allocation method for the cost of a regional facility must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.[455] However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if there is an agreement for the original region to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the entities in the original region.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this Final Rule.[456]

587. The Proposed Rule required each cost allocation method to comply with the following interregional cost allocation principles:

(1) The costs of a new interregional facility must be allocated to each transmission planning region in which that facility is located in a manner that is at least roughly commensurate with the estimated benefits of that facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.

(2) A transmission planning region that receives no benefit from an interregional

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[451] *See* discussion *infra* section IV.E.5.

[452] Public utility transmission providers may continue to enter into such agreements as a means of complying with this Final Rule, but any such agreements that are incorporated into the public utility transmission provider's OATT by reference must be consistent with or superior to this Final Rule.

[453] *See Illinois Commerce Commission,* 576 F.3d 470 at 476–77 (stating that ''[w]e do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars''). *See also MISO Transmission Owners,* 373 F.3d 1361 at 1369 (stating that ''we have never required a ratemaking agency to allocate costs with exacting precision''); *Sithe,* 285 F.3d 1 at 5.

[454] As discussed above, the Commission proposed to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements established by state or federal laws or regulations that drive transmission needs. As discussed above, we adopt this requirement in this Final Rule.

[455] In addition, the Commission preliminarily found that this principle does not affect the cross-border cost allocation methods developed by PJM and MISO in response to Commission directives related to their intertwined configuration. *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, at P 10; *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084; *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,102. As noted above, we adopt this finding in this Final Rule.

[456] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164.

transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility.[457]

(3) If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

(4) Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located. However, the interregional planning process must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if there is an agreement among the transmission providers in the regions in which the facility is located to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of the upgrades within the transmission planning regions in which the facility is located.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out and explained in detail in the compliance filing for this rule.

588. The Proposed Rule also states that public utility transmission providers will have the first opportunity to develop cost allocation methods for regional and interregional transmission facilities in consultation with stakeholders. In the event that no agreement can be reached, the Commission would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements.

b. Comments on Use of Principles-Based Approach

589. Many commenters generally support the use of cost allocation principles although this support is often expressed as part of general support for the Proposed Rule's six proposed cost allocation principles as a package.[458] For example, Dominion believes that by providing cost allocation principles linked to planning, the Commission has taken the correct approach without being overly prescriptive. Dayton Power and Light states that these principles help to reduce uncertainty and provide guidance to interested stakeholders. Energy Future Coalition Group states that the proposed principles follow the direction laid out by the court in the *Illinois Commerce Commission* case, and address legitimate concerns that have been raised by some opponents of broad cost allocation policy over the past two years. On the other hand, as discussed above,[459] some comments oppose any generic action on regional and interregional cost allocation and therefore do not support the use of cost allocation principles to support such action.

590. Almost all commenters urge the Commission not to adopt a ''one-size-fits-all'' approach to cost allocation and to retain regional and interregional flexibility.[460] For example, APPA and Transmission Agency of Northern California state that the Commission should not prescribe a uniform approach to interregional transmission cost allocation, and should allow for regional and interregional differences. Transmission Agency of Northern California states that this issue is being addressed at a level where local and regional differences can be addressed more fully, and that it supports the Proposed Rule's assumption that this ongoing process should not be disrupted by this rulemaking.

591. Several commenters ask the Commission to address the Proposed Rule's provision regarding ''in the event that no agreement can be reached.''[461] They contend that if the Commission adopts a rule providing that it would select a backstop cost allocation method in the event that stakeholders within a region cannot agree to a regional cost allocation method or if regions cannot agree on a cost allocation method for interregional projects, the Commission should provide additional guidance that would help stakeholders to reach agreement. For example, Multiparty Commenters request that the Commission clarify: The level of stakeholder agreement that is acceptable; what would be evidence of an impasse; whether the Commission will defer to the majority; and whether the Commission will extend the time in which to make compliance filings to afford more time to obtain an agreement. Similarly, for interregional cost allocation, Anbaric and PowerBridge recommend that the Commission stipulate a reasonable period of time for regions to reach agreement on a proposed interregional cost allocation method.

592. Some commenters recommend that the Commission adopt an interregional default cost allocation method if regions cannot agree to such a method themselves, although they note that specific projects will involve unique facts and circumstances. Anbaric and PowerBridge believe that, if regions cannot agree on an interregional cost allocation method, the Commission could impose an agreement based on the facts and circumstances of the project. Massachusetts Municipal and New Hampshire Electric state that, even if an interregional default method is implemented, whether by mutual agreement or by Commission directive, disputes will arise about the application of that method to a given set of facts. Massachusetts Municipal and New Hampshire Electric suggest that the Commission can address these concerns by adopting expedited hearing procedures to be applied in such cases.

593. Other commenters suggest a variation on or alternative to the idea that the Commission adopt a default cost allocation method for regional and interregional cost allocation if stakeholders or regions cannot come to a consensus themselves.[462] Wind Coalition states that having a default cost allocation method would allow construction to commence while an alternative cost allocation method is being developed, if needed. It states that this would be particularly needed for cross-border cost allocation because there are currently few interregional agreements on cost allocation. Wind Coalition also states that matching cost

[457] For example, a DC line that runs from a first transmission planning region, through a second transmission planning region, and into a third transmission planning region, with no tap in the second region, may not provide any benefits to the second region.

[458] *E.g.,* DC Energy; WIRES; Dominion; and Dayton Power and Light.

[459] *See* discussion *supra* section II.

[460] *E.g.,* Large Public Power Council; Kansas Corporation Commission; and Nebraska Public Power District.

[461] *E.g.,* Anbaric and PowerBridge; AWEA; MidAmerican; Multiparty Commenters; and Southern Companies.

[462] *E.g.,* American Transmission; AWEA; NextEra; and Wind Coalition.

allocation with a proactive regional or interregional plan is important for justifying regional cost sharing.

594. Some commenters argue that, if a region or regions fail to agree on a method, the Commission should not select a default cost allocation method and also should not select a cost allocation method based on the record here.[463] APPA contends that adoption of a default cost allocation method or particular cost allocation principles or guidelines would influence the prospects for successful regional and interregional negotiation because stakeholders that support the default method will be unwilling to negotiate, knowing that if no agreement is reached, their preferred method will be adopted as the default. PSEG Companies argue that adoption of a single default cost allocation method would be inconsistent with the Proposed Rule's ''beneficiary pays'' approach. PSEG Companies believe that the ''roughly commensurate'' standard that the *Illinois Commerce Commission* decision requires will be satisfied only by happenstance under a default cost allocation method. PSEG Companies also disagree with comments by National Grid, AEP, and others that the Commission should institute a default cost allocation method for transmission planning regions that would apply regardless of the nature of the facilities planned (*i.e.,* reliability or economic). PSEG Companies suggest that the Commission clarify how interregional cost allocation will be handled in the absence of an interregional agreement, and it should make clear that the existence of such an agreement is a prerequisite to the assignment of costs to another transmission planning region and its customers. PSEG Companies also state that, if certain regions decline to enter into interregional agreements, the Commission should adopt a ''do not harm'' standard applicable to such regions as a corollary principle, that is, no region may plan its system in a way that would impose costs on other regions.

595. Some commenters suggest a particular default method that the Commission should adopt if it decides to have a default cost allocation method, such as the SPP highway/byway mechanism.[464] However, other commenters express concern with establishing a ''one-size-fits-all'' default allocation method.[465] In particular, New England States Committee on Electricity and Identified New England Transmission Owners urge the Commission to reject recommendations to adopt the highway/byway mechanism as a default cost allocation method, instead asking the Commission to respect regional differences. Sunflower and Mid-Kansas submit that the Final Rule should provide for two-third regional (or interregional) allocation of costs and one-third to the ultimate sink zone for all network upgrades approved through an interregional plan that are needed for variable energy resource integration.

596. With respect to the question of whether the Commission should establish an interim cost allocation method until stakeholders have time to reach consensus, AWEA states that the current market structure and the mechanisms used to allocate costs between transmission providers outside organized market regions needs to mature further before transmission providers in many of these market regions will be able to fully comply with the Proposed Rule. It states that if transmission providers outside organized market regions cannot demonstrate a binding cost allocation method as envisioned by the Proposed Rule, it would be appropriate for the Commission to consider an interim method to address cost allocation in those regions, such as using an ''intertie open season'' to create a record about the appropriate allocation of costs.

597. NextEra suggests that, for non-RTO regions, regional cost recovery should be promoted by an adder on the transmission rates of public utility transmission providers (and extended to non-jurisdictional utilities via reciprocity). Southern Companies respond that this approach is not feasible because it does not address the fact that their OATT recovers only the share of the cost attributable to their provision of wholesale transmission service. Southern Companies state that even with an adder, third parties would be limited to recovering approximately 15 percent of their transmission costs, which is comparable to Southern Companies' cost recovery.

598. Massachusetts Departments and MidAmerican state that the Commission should narrowly apply any authority it has to develop a cost allocation method only for specific projects rather than requiring an established mechanism for all projects. For instance, MidAmerican proposes that the Commission adopt a default cost allocation method that would be used only if the stakeholders fail to agree regarding a 500 kV or higher alternative current facility (except high voltage direct current projects) that is identified by the planning process as providing widespread benefits. In this limited case, MidAmerican suggests that the Commission adopt a streamlined dispute resolution mechanism with a rebuttable presumption in favor of specified regional and interregional cost allocation methods. MidAmerican states that the record in the proceeding before the Commission on remand from the Seventh Circuit *Illinois Commerce Commission* opinion, demonstrates the reliability, economic, and societal benefits of 500 kV and above transmission, and it also documents that these benefits are realized regionwide whenever extra-high voltage transmission is deployed.

599. Wisconsin Electric states that it may be useful to consider the extent to which statewide stakeholder collaboratives could be effective in helping to resolve interstate cost allocation and cost recovery controversies. It points to California's Renewable Energy Transmission Initiative, which distinguishes stakeholders who are willing to work in good faith to resolve a project from those who only oppose transmission for self-interested reasons. Northwestern Corporation (Montana) is concerned that the proposal could have uneconomic consequences in that a high-cost allocation solution could be involuntarily allocated to an unwilling entity that has a lower-cost solution. Northern Tier Transmission Group is also worried about the difficulties that would arise in the context of allocating costs to entities that are unwilling to incur them.

600. Some commenters state that the Commission should not close the door on existing or evolving processes.[466] Salt River Project states that requiring involuntary cost sharing would risk foreclosure of promising alternatives and superior options for reliable and least-cost service for customers. Salt River Project is also concerned that arbitrary solutions could result that fail to honor local and regional interests.

[463] *E.g.,* APPA and PSEG Companies.

[464] Several commenters suggested this method including AWEA, Multiparty Commenters, and NextEra.

[465] *E.g.,* Connecticut & Rhode Island Commissions; Kansas Corporation Commission; Salt River Project; WIRES; and Wisconsin Electric.

[466] In addition, WIRES also notes that a default method where regional parties reach an impasse may look more attractive if the Commission's principles provide only generalized guidance. However, WIRES states that greater reliance on principled, up-front guidance for allocating the costs of transmission can provide a high degree of reassurance to parties engaged in negotiating a method. It states that only the Commission can provide this level of certainty.

601. Dominion states that it is unlikely any imposed allocation method will generate uniform agreement or consensus so if competing principled approaches are proposed, the Commission should not make a ruling in favor of one over the other, but consider whether a blended approach could result in a just and reasonable solution. Southern Companies state that the policies of promoting the expansion of the transmission grid would be better served by developing a set of reasonable cost allocation principles that would be used to develop a cost allocation method only when an actual, multi-jurisdictional project is pursued. With respect to interregional cost allocation, New York Transmission Owners argue that it is neither necessary nor reasonable for the Commission to impose an interregional cost allocation method if one is not agreed to by the regions.

602. Further, other commenters tell us that principles alone are not enough, and propose alternative solutions. These comments are summarized and addressed below in the discussion of the proposed cost allocation principles.

c. Commission Determination

603. The Commission requires each public utility transmission provider to show on compliance that its cost allocation method or methods for regional cost allocation and its cost allocation method or methods for interregional cost allocation are just and reasonable and not unduly discriminatory or preferential by demonstrating that each method satisfies the six cost allocation principles. Commission determinations on each cost allocation principle are set out in the subsections below. The six regional cost allocation principles apply to, and only to, a cost allocation method or methods for new regional transmission facilities selected in a regional transmission plan for purposes of cost allocation. The six analogous interregional cost allocation principles apply to, and only to, a cost allocation method or methods for a new transmission facility that is located in two neighboring transmission planning regions and accounted for in the interregional transmission coordination procedure in an OATT. These cost allocation principles do not apply to other new transmission facilities and therefore do not foreclose the opportunity for a developer or individual customer to voluntarily assume the costs of a new transmission facility, as discussed further below in the Participant Funding subsection.

604. We adopt the use of cost allocation principles because we do not want to prescribe a uniform method of cost allocation for new regional and interregional transmission facilities for every transmission planning region. To the contrary, we recognize that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. Therefore, we retain regional flexibility and allow the public utility transmission providers in each transmission planning region, as well as pairs of transmission planning regions, to develop transmission cost allocation methods that best suit the needs of each transmission planning region or pair of transmission planning regions, so long as those approaches comply with the regional and interregional cost allocation principles of this Final Rule.

605. The Commission recognizes that a variety of methods for cost allocation may satisfy a set of general principles. For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[467] Similarly, other methods that would allocate costs to a narrower class of beneficiaries may be appropriate, provided that the methods reflect an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region or pairs of transmission planning regions.

606. In response to comments that request further detail from the Commission on what an appropriate cost allocation method would look like, we conclude that public utility transmission providers in each transmission planning region or pair of transmission planning regions must be allowed the opportunity to determine for themselves the cost allocation method or methods to adopt based on their own regional needs and characteristics, consistent with the six cost allocation principles. With the exception of the limitation on participant funding explained below, we decline to prejudge any particular method or set of methods generically in this Final Rule.

607. In the event of a failure to reach an agreement on a cost allocation method or methods, the Commission will use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements. Public utility transmission providers must document in their compliance filings the steps they have taken to reach consensus on a cost allocation method or set of methods to comply with this Final Rule, as thoroughly as practicable, and provide whatever information they view as necessary for the Commission to make a determination of the appropriate cost allocation method or methods. Each public utility transmission provider must make an individual compliance filing that includes its own proposed method or set of methods of allocating costs and explains how it believes its method or methods satisfy the cost allocation principles and is appropriate for its transmission planning region or pair of transmission planning regions. Groups of public utility transmission providers that agree on a proposed method or methods may make a coordinated filing or filings with their common views. The public utility transmission providers in each transmission planning region or pair of transmission planning regions will have the burden of demonstrating that sufficient effort has been made to comply with the requirements of this Final Rule.

608. Interested parties will be provided an opportunity to comment on these compliance filings, thereby creating a record on which the Commission could develop an appropriate cost allocation method or methods, or establish further procedures to do so. We do not impose other specific filing requirements for what the record should contain. As with any other proceeding before the Commission, should more information become necessary during the Commission's review process, the Commission may request more information from the parties at that time.

609. The Commission will consider in response to compliance filings all issues raised by commenters, such as what constitutes an impasse, whether there should be deference to the majority, and whether granting additional time for the region to continue negotiations would be appropriate. The procedural mechanisms used by the Commission in response to compliance filing(s) will depend on the nature of remaining

[467] We address comments below suggesting that the cost allocation principles be applied to require regional cost sharing for all transmission facilities at 345 kV or higher.

disputes and what issues are still at stake that are preventing the public utility transmission providers in each transmission planning region or pair of transmission planning regions from reaching a consensus. The Commission will not prejudge the outcome of the dispute by stating at this time whether there should be deference to the views of any particular segment of stakeholders, as suggested by Multiparty Commenters.

610. We decline to adopt a default regional or interregional cost allocation method in this Final Rule. We decline to do so for reasons similar to the reasons we declined to impose a uniform cost allocation method for all transmission planning regions. Many factors may make it appropriate for different transmission planning regions to have different cost allocation methods. It thus would not be practical or reasonable for the Commission to establish such default methods. We agree with APPA and others that having a known default method would cause those who favor it not to negotiate in good faith for an alternative cost allocation method. For these same reasons, we will not establish an interim cost allocation method that applies between the time of the issuance of this Final Rule and the time when stakeholders reach a consensus.

611. The twelve regional and interregional proposed cost allocation principles are discussed below in pairs of six separate subsections. Because the proposed cost allocation principles for regional transmission facilities are very similar to the proposed cost allocation principles for interregional transmission facilities, almost all commenters discussed them together as if they were a single principle. Therefore, the Commission discusses the corresponding sets of cost allocation principles together and, except where otherwise indicated, the Commission determinations regarding each set of cost allocation principles apply to both the regional and interregional transmission facilities in a regional transmission plan for purposes of cost allocation. The cost allocation principles in the Final Rule apply only to those new transmission facilities selected in a regional transmission plan for purposes of cost allocation and new transmission facilities subject to the cost allocation provision of the interregional coordination procedures in an OATT.

2. Cost Allocation Principle 1—Costs Allocated in a Way That is Roughly Commensurate With Benefits [468]

a. Comments

612. Many commenters generally support the Commission's first proposed cost allocation principle for both regional and interregional cost allocation, which provides that the costs of transmission facilities must be allocated to those that benefit in a manner at least roughly commensurate with the estimated benefits received.[469] For example, Transmission Access Policy Study Group states that the roughly commensurate standard appears to be consistent with the *Illinois Commerce Commission* decision and cost causation principles. Additionally, Westar states that transmission customers in a region should not pay for transmission projects that do not provide commensurate benefits and that only transmission projects that have been thoroughly reviewed in the regional process, show a benefit to the region and are approved by the transmission provider should be included in regional rates. Commenters also generally support the Proposed Rule's proposal to adhere to cost causation principles and also support a ''beneficiaries pay'' approach.[470] Dayton Power & Light comments that ''beneficiaries pay'' is the touchstone principle for cost allocation. American Forest & Paper argues that such an approach provides for better incentives for analysis of costs and alternatives.

613. Several commenters, however, support a broader definition of benefits and beneficiaries.[471] NextEra argues that the Final Rule should mandate that planning processes consider various types of benefits, rather than leaving it to a transmission provider's discretion. Old Dominion asserts that adopting a narrow approach to assessing benefits for cost allocation purposes would ignore the broader benefits associated with maintaining and expanding the regional high voltage transmission system—such as more options when making resources decisions in regional markets. Old Dominion notes that restricting the cost causation benefits to a snapshot in time would be problematic for dynamic high voltage regional transmission facilities. National Grid supports a cost allocation method that takes into account both the quantitative and qualitative benefits of transmission. Xcel suggests that the Commission permit methods, such as SPP's highway/byway approach, which broadly allocate costs based on general determination of the benefits provided to a region and stakeholders. AWEA and Multiparty Commenters state that it does not make sense to use cost allocation mechanisms that look only at public policy requirements established by existing state or federal laws or regulations because transmission assets are used for 40 years or longer, and they encourage the Commission to clarify that the appropriate cost allocation mechanisms should take into account the benefits of transmission in addressing likely future public policy requirements as well as existing ones. American Antitrust Institute recommends that the pro-competitive benefits of transmission be recognized.

614. PUC of Ohio recommends that the definition of beneficiary also should include those who gain from the ability to place electricity onto the grid. It states that load should not be solely burdened with the costs of the transmission grid; generation should be responsible for its fair share of the costs. Maine Parties agree, characterizing a beneficiary pays as more consistent with cost causation principles than a cost socialization method.

615. In response to comments supporting a broader definition of benefits, Powerex states that it disagrees that the Proposed Rule is intended to allow for allocation methods that could impose cross-subsidization and states that cost allocation methods for jurisdictional facilities must adhere to cost causation principles. Powerex argues that state or federal public policy requirements do not constitute evidence of a general or undifferentiated benefit to all market participants. Thus, Powerex argues, the Final Rule should emphasize that cost causation principles are and will remain the foundation of all acceptable cost allocation methods and make clear that the Commission rejects cost allocation proposals or outcomes that depart from this principle by promoting cross-subsidization.

616. PSEG Companies take issue with the Proposed Rule's suggestion that the determination of who constitutes a beneficiary may be based on an assessment of ''likely future scenarios,''

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[468] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[469] *E.g.,* Bay Area Municipal Transmission Group; Santa Clara; Consolidated Edison and Orange & Rockland; Transmission Access Policy Study Group; United States Senators Dorgan and Reid; Professor Ignacio Perez-Arriaga; New York ISO; New York PSC; New York Transmission Owners; Westar; City and County of San Francisco; Conservation Law Foundation; Energy Future Coalition Group; Solar Energy Industries; and EarthJustice.

[470] *E.g.,* Dayton Power & Light; Conservation Law Foundation; and American Forest & Paper.

[471] *E.g.,* NextEra; AWEA; EarthJustice; and Atlantic Grid.

arguing that regional planners should not be prognosticators and that the more ''scenarios'' that are introduced, the more inexact and speculative their proposed plans and cost allocation determinations will become.

617. Dayton Power & Light seeks clarification of what it considers an ambiguity in regional and interregional Principle 1, which allows a regional transmission planning process to consider the extent to which facilities ''in the aggregate'' provide benefits.[472] Dayton Power & Light states that this language could be taken to mean that if the existing network benefits a utility, then that is a benefit that justifies the utility allocating to it the incremental costs created by a new transmission project located far away, even if the project did not provide incremental benefits. According to Dayton Power & Light, this result would be inconsistent with *Illinois Commerce Commission* decision.

618. Some commenters also request that the proposed principle be expanded so that the costs of transmission facilities are allocated to those within the planning region and adjacent planning regions that benefit from those facilities.

619. Some commenters request clarification regarding what constitutes ''benefits'' to be considered in any cost allocation method.[473] Alabama PSC states that the cost allocation proposals are too vague and potentially overbroad, and it requests that the Commission make clear that costs cannot be recovered from retail customers. WIRES requests that the Commission articulate more clearly the definitions, presumptions, and methods associated with the beneficiary pays approach.

620. A number of commenters differ on what constitutes ''benefits'' and who constitutes ''beneficiaries.'' Several commenters state concern that the definition of ''benefits'' could be interpreted too broadly, particularly with respect to transmission projects driven by public policy goals.[474] Atlantic Wind Connection requests clarification as to how the costs associated with public policy initiatives would be fairly assigned to beneficiaries, so that a results-oriented action plan emerges from the process. Transmission Access Policy Study Group argues that benefits are difficult to quantify and cautions the Commission against including generalized social or environmental benefits in cost allocation calculations. Transmission Access Policy Study Group and Colorado Independent Energy Association argue that production cost savings by itself is not sufficient to identify the universe of beneficiaries.[475] Transmission Access Policy Study Group argues, however, that the Commission should clarify that it will not accept cost allocation methods that assign costs regionally based on a presumption of some general, unquantified regional benefits or vague assertions of possible future benefits.

621. Some commenters raise similar concerns about the difficulty of quantifying benefits, and they suggest that benefits resulting in allocation of costs be direct, clear, and identifiable.[476] Other commenters also believe it is important to make sure cost allocation mechanisms do not favor long-line transmission development or artificially depress the value of local renewable resources.[477] In its reply comments, Ohio Consumers' Council agree that benefits should not be defined too broadly and recommends that the Commission strictly adhere to cost causation principles in implementing the Final Rule. Further, Ohio Consumers' Council suggests that the Commission uphold cost causation principles by requiring substantial evidentiary showings of benefits and costs prior to approving the imposition of regional or interregional transmission costs on consumers. With respect to interregional cost allocation, North Carolina Agencies contend that if the Commission assumes benefits too broadly, a public utility's retail customers may bear a share of costs based on the policy objectives of other states. Alabama PSC shares this concern. According to Western Area Power Administration, only the direct beneficiaries of a project, *i.e.,* beneficiaries that make direct use of the facilities, should be counted as ''beneficiaries,'' and to the extent that costs are allocated to such beneficiaries, only the costs associated with the least-cost method of achieving the benefits should be allocated. LS Power states that it is important for the Final Rule to acknowledge that the factors that drive transmission planning do not fully define the range of beneficiaries.

b. Commission Determination

622. The Commission adopts the following Cost Allocation Principle 1 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 1: The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.[478]

and

Interregional Cost Allocation Principle 1: The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[479]

623. As discussed above,[480] requiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts. As the Commission stated in Order No. 890, the one factor that it weighs when considering a dispute over cost allocation is whether a proposal

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[472] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164, 174.

[473] *E.g.,* California Municipal Utilities; Northern Tier Transmission Group; Omaha Public Power District; Gaelectric; and Atlantic Grid.

[474] *E.g.,* Florida PSC; Public Power Council; Transmission Dependent Utility Systems; and Coalition for Fair Transmission Policy.

[475] *E.g.,* Transmission Access Policy Study Group; and Colorado Independent Energy Association.

[476] *E.g.,* East Texas Cooperatives and G&T Cooperatives.

[477] *E.g.,* New England States Committee on Electricity; Nebraska Public Power District; Sacramento Municipal Utility District; California State Water Project; and Northeast Utilities.

[478] In the Proposed Rule, Regional Cost Allocation Principle 1 referred to ''public policy requirements established by State or Federal laws or regulations that may drive transmission needs.'' As defined in P 0 of this Final Rule, we use ''Public Policy Requirements'' in Regional Cost Allocation Principle 1 and throughout our discussion of the Cost Allocation Principles.

[479] We note that the phrase ''individually or in the aggregate'' is not contained in Interregional Cost Allocation Principle 1 because interregional transmission facilities are considered facility by facility by pairs of transmission planning regions, unless pairs of transmission planning regions choose to do otherwise.

[480] *See* discussion *supra* P 0 and section V.B.

fairly assigns costs among those who cause the costs to be incurred and those who otherwise benefit from them.[481] Therefore, it is appropriate here to adopt a cost allocation principle that includes as beneficiaries those that cause costs to be incurred or that benefit from a new transmission facility.

624. However, the Commission is not prescribing a particular definition of ''benefits'' or ''beneficiaries'' in this Final Rule. In our view, the proper context for further consideration of these matters is on review of compliance proposals and a record before us. Moreover, allowing the flexibility to accommodate a variety of approaches can better advance the goals of this rulemaking. The cost allocation principles are not intended to prescribe a uniform approach, but rather each public utility transmission provider should have the opportunity to first develop its own method or methods. Also, we recognize that regional differences may warrant distinctions in cost allocation methods.

625. While some commenters express concerns that the definition of benefits could be interpreted too broadly or too narrowly, we do not believe that further defining ''benefits'' in this Final Rule is a necessary or appropriate means to ensure that this will not be the case. We expect that concerns regarding overly narrow or broad interpretation of benefits will be addressed in the first instance during the process of public utility transmission providers consulting with their stakeholders. If such interpretations should emerge, we can more effectively ensure that the term is not given too narrow or broad a meaning by considering a specific proposal and a record than by attempting to anticipate and rule on all possibilities before the fact. This point applies equally to the comments that note the potential difficulties in quantifying benefits. We note in response to Transmission Access Policy Study Group, that any benefit used by public utility transmission providers in a regional cost allocation method or methods must be an identifiable benefit and that the transmission facility cost allocated must be roughly commensurate with that benefit. Western Area Power Administration takes the position that beneficiaries should be limited to those that it describes as making direct use of the transmission facilities in question, but this fails to acknowledge that other benefits may accrue to an interconnected transmission grid.

[481] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

626. We agree with Powerex that a departure from cost causation principles can result in inappropriate cross-subsidization. This is why cost causation is the foundation of an acceptable cost allocation method. In response to PSEG Companies, we disagree that basing a determination of who constitutes a ''beneficiary'' on ''likely future scenarios'' necessarily would result in inexact and speculative proposed transmission plans and cost allocation methods. Scenario analysis is a common feature of electric power system planning, and we believe that public utility transmission providers are in the best position to apply it in a way that achieves appropriate results in their respective transmission planning regions.

627. In response to Dayton Power & Light, the provisions of Regional Cost Allocation Principle 1 regarding determination of the beneficiaries of transmission facilities ''individually or in the aggregate'' refer only to cost allocation for new transmission facilities. The public utility transmission providers in a transmission planning region may propose a cost allocation method that considers the benefits and costs of a group of new transmission facilities, although they are not required to do so. We did not intend this language to be a finding that the benefits of existing transmission facilities in and of itself may justify cost sharing for new transmission facilities. We are not ruling on that matter in this Final Rule.

628. We also decline to expand, as requested by some commenters, the scope of beneficiaries for new transmission facilities such that costs may be involuntarily allocated to those within an adjacent planning region that benefit from those facilities. As discussed in adopting Cost Allocation Principle 4 below, the allocation of the cost of a transmission facility that is located entirely within one transmission planning region may not be subject to a regional cost allocation method or methods pursuant to this Final Rule that assigns some or all of the cost of that transmission facility to beneficiaries in another transmission planning region without reaching an agreement with those beneficiaries.[482]

629. Finally, if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.

[482] *See* discussion *infra* section IV.E.5.

3. Cost Allocation Principle 2—No Involuntary Allocation of Costs to Non-Beneficiaries [483]

a. Comments

630. Most of the commenters that addressed proposed Cost Allocation Principle 2 support it.[484] Ad Hoc Coalition of Southeastern Utilities and Nebraska Public Power District state that while the proposition in Cost Allocation Principle 2 might seem self supporting, they understand that there are those who would encourage the Commission to mandate regional or even interconnectionwide cost sharing, but the Commission's decision to decline to do so is sensible.

631. Some commenters who express general support also express some concerns. For example, MISO Transmission Owners urge the Commission to ensure that this principle does not contribute to free rider problems.

632. Some commenters are concerned that the principle could be interpreted too narrowly or too broadly. For instance, NextEra asks that the Commission construe the ''no benefit'' standard narrowly by providing that there is a benefit if a customer receives any benefit from the transmission facility, including an economic, reliability, or public policy benefit, particularly at or above certain voltage levels, over a reasonable period of time.

633. Some commenters do not support the principle and raise concerns that the ''no benefits'' language in the principle will rarely, if ever, be applicable to any transmission customer.[485] East Texas Cooperatives argue that by protecting only those that receive no discernible benefit, this principle conflicts with court precedent stating that the Commission cannot approve a pricing scheme that requires utilities to pay for facilities from which its members derive only trivial benefits. East Texas Cooperatives states that Principle 2 does not go far enough, and the Commission should clarify that only those customers who are reasonably expected to receive non-trivial benefits can be allocated costs. Other

[483] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[484] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Connecticut & Rhode Island Commissions; New England States Committee on Electricity; New York ISO; and New York PSC.

[485] *E.g.,* Transmission Dependent Utility Systems and East Texas Cooperatives.

commenters, such as E.ON and Public Power Council, are worried that there will be stranded costs if a planning process exaggerates the benefits resulting from a particular project. Public Power Council believes the Commission should permit cost allocations that mitigate the risk of stranded costs and give due consideration to the impact on ratepayers prior to allocating costs.

634. On the other hand, Xcel is concerned that the principle, taken at face value, gives parties the ability to ''opt out'' of cost allocation arising from specific projects even as it offers parties the opportunity to participate fully in the planning process. Xcel maintains that the Order No. 890 transmission planning process and the linkage between transmission planning and cost allocation render moot any participant's argument that it receives no benefit. Xcel argues that the Order No. 890 planning principles are designed to result in the best projects to meet the needs of the planning region, and therefore it is unlikely that participants in the planning process would produce a plan with a project or set of projects that do not provide benefits to stakeholders.

635. Alliant Energy asks whether the Commission intended that membership in an ISO or RTO eliminates the prohibition of cost allocation for transmission projects to those entities that do not benefit. Alliant Energy does not believe this was the Commission's intent, but is seeks clarification to confirm its view.

636. Alliant Energy also seeks clarification of the term ''transmission facilities'' within the context of this principle. It asks whether the Commission intended that the principle be applied on a project-by-project basis, within the context of the entire regional transmission plan, or something in between. Alliant Energy believes that such evaluations should be done on a holistic basis, noting that some individual projects will benefit certain entities more than others but that the evaluation of benefits and costs within the context of a cost allocation determination could reasonably include the cumulative impact of a collection of projects.

b. Commission Determination

637. The Commission adopts the following Cost Allocation Principle 2 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 2: Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.[486]

and

Interregional Cost Allocation Principle 2: A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.

The principle expresses a central tenet of cost causation and is thus essential to proper cost allocation.

638. In response to MISO Transmission Owners that Principle 2 might contribute to free rider problems, we agree that it, like all the other principles adopted in this Final Rule, requires careful consideration and application to ensure that they are implemented appropriately in practice. In response to NextEra, we decline to establish a threshold voltage level to define which benefits would be ineligible for cost allocation in this Final Rule.

639. East Texas Cooperatives is concerned that the Commission is protecting only those that receive no benefits but not those who derive only trivial benefits. It cites the Seventh Circuit's statement in *Illinois Commerce Commission* that emphasized that the Commission is not authorized to approve cost allocation methods that require entities that receive no benefits or benefits that are trivial in relation to the costs to be borne. We note that the court used the term ''trivial'' in a relative sense, *i.e.,* benefits that are trivial in relation to the costs assigned. This is implied in the concept of cost causation, and we therefore see no reason to amend the Principle 2 to include reference to it. Principle 1 requires that costs be allocated in a way that is roughly commensurate with the benefits received. This precludes an allocation where the benefits received are trivial in relation to the costs to be borne. Any beneficiaries that believe that the application of the cost allocation method or methods would assign to them costs for benefits, which are trivial, in relation to those costs is free to make a FPA section 205 or 206 filing.

640. We also require that every cost allocation method or methods provide for allocation of the entire prudently incurred cost of a transmission project to prevent stranded costs. We disagree with Xcel that the Principle 2 gives parties the ability to opt out of a Commission-approved cost allocation for a specific transmission project if they merely assert that they receive no benefits from it. Whether an entity is identified as a beneficiary that must be allocated costs of a new transmission facility is not determined by the entity itself but rather through the applicable, Commission-approved transmission planning processes and cost allocation methods. Permitting each entity to opt out would not minimize the regional free rider problem that we seek to minimize in this Final Rule.

641. With respect to Alliant Energy's request for clarification regarding RTO or ISO membership, we clarify that all the cost allocation principles, including Cost Allocation Principle 2 apply the allocation of costs to all new transmission facilities selected in the regional transmission plan for purposes of cost allocation, including RTO and ISO regions. In response to Alliant Energy's request to clarify whether the Commission intended that the principle be applied on a project-by-project basis, within the context of the entire regional transmission plan, we reiterate that the public utility transmission providers in a transmission planning region may propose a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, although they are not required to do so. To the extent they propose a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, and adequately support their proposal, Cost Allocation Principle 2 would not require a showing that every individual transmission facility in the group of transmission facilities provides benefits to every beneficiary allocated a share of costs of that group of transmission facilities. However, it is required that the aggregate cost of these transmission facilities be allocated roughly commensurate with aggregate benefits.

4. Cost Allocation Principle 3—Benefit to Cost Threshold Ratio[487]

a. Comments

642. Many commenters support the Commission's proposed Cost Allocation Principle 3, finding it to be a reasonable approach that would result in the construction of new transmission

[486] We added the words ''any of'' to the Regional Cost Allocation Principle 2 stated in the Proposed Rule to be consistent with interregional cost allocation Principle 2. We also added ''transmission'' before ''facilities'' to clarify the term in this Regional Cost Allocation Principle 2 and throughout our discussion of the Cost Allocation Principles.

[487] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

projects.[488] For example, ITC Companies states that the Commission's recommended cost threshold ratio is a necessary specification to prevent measures such as the sliding cost benefit ratio employed by MISO, which can require up to a 3 to 1 benefit to cost ratio for large regional long term transmission projects and which has served to frustrate the construction of market efficiency projects. American Transmission believes that the Commission's proposal seems like a reasonable threshold that would likely result in projects actually being constructed.

643. Nonetheless, some commenters raise specific concerns. While generally supportive of the proposal, MISO Transmission Owners suggest that transmission providers and stakeholders in each planning region be permitted to develop a benefit to cost ratio that is appropriate for that region, provided that ratios are not set so high as to preclude any projects from being built. Similarly, MISO Transmission Owners argue that transmission providers and stakeholders should be permitted to develop appropriate criteria for defining benefits and costs. They also state that the Final Rule should indicate that any benefit to cost ratio for interregional transmission facilities should not supersede the ratio for a region's regional cost allocation. Transmission Dependent Utility Systems support this principle as a general concept, but they argue that it should be modified to ensure that the implementation of any cost benefit analysis is transparent to customers.

644. Several commenters oppose the use of a fixed benefit-cost threshold ratio.[489] A number of them stress the difficulties in quantifying benefits.[490] Some commenters argue that the Commission should focus on regional circumstances.[491] Northern Tier Transmission Group suggests that the Commission's focus should be on defining the types of benefits to be measured and how to measure them, rather than establishing a set threshold. Massachusetts Departments are concerned that a failure to reflect the full menu of benefits that could be realized by a proposed project could distort the balance between costs and benefits, and could preclude some beneficial projects at the planning stage that would have otherwise been approved. NextEra requests that benefits for this assessment should cover only economic benefits identified with the project, and not reliability or public policy benefits, as those benefits cannot be quantified in a similar manner.

645. Some commenters would like the Commission to establish either a higher or a lower benefit-cost ratio threshold. New York PSC believes that the proposed threshold is extremely low and does not adequately account for uncertainty in cost estimates and potential cost overruns. Connecticut & Rhode Island Commissions and Massachusetts Departments agree. On the other hand, AWEA, Wisconsin Electric, and NextEra urge the Commission to lower the proposed threshold. AWEA argues that if the Commission adopts the proposed threshold, it should be applied as a ceiling to ensure fair treatment for projects that have broad benefits over time. MEAG Power responds to AWEA's argument for a lower threshold, arguing that AWEA's proposal would unfairly shift to customers all risks associated with project development.

b. Commission Determination

646. The Commission adopts the following Cost Allocation Principle 3 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 3: If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation,[492] it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio.

and

Interregional Cost Allocation Principle 3: If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation.[493] The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

647. Cost Allocation Principle 3 does not require the use of a benefit to cost ratio threshold. However, if a transmission planning region chooses to have such a threshold, the principle limits the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan. Further, it allows public utility providers in a transmission planning region to use a lower ratio without a separate showing and to use a higher threshold if they justify it and the Commission approves a greater ratio.

648. Allowing for a transparent benefit to cost ratio may help certain transmission planning regions to determine which transmission facilities have sufficient net benefits to be selected in the regional transmission plan for purposes of cost allocation. For example, public utility transmission providers in a transmission planning region may want to use such a ratio to account for uncertainty in the calculation of benefits and costs. However, by requiring that a benefit to cost ratio, if adopted, not exceed 1.25 to 1 unless the public utility transmission providers in a transmission planning region justify, and the Commission approves, a greater ratio, will ensure that the ratio is not so high that transmission facilities with significant positive net benefits that would otherwise be selected in the regional transmission plan for purposes of cost allocation are not excluded from the regional transmission plan for purposes of cost allocation despite a positive ratio. The Commission therefore rejects requests to adopt a higher or lower threshold ratio, as advocated by some commenters.

649. In response to specific comments on this principle, the Commission agrees that a benefit to cost ratio should not be set so high as to preclude certain beneficial transmission projects from

[488] *E.g.,* ITC Companies; American Transmission; Omaha Public Power District; PSEG Companies; and Six Cities.

[489] *E.g.,* Northeast Utilities; Connecticut & Rhode Island Commissions; and Michigan Citizens Against Rate Excess.

[490] *E.g.,* Xcel and Northern Tier Transmission Group.

[491] *E.g.,* Michigan Citizens Against Rate Excess; Xcel; and Massachusetts Departments.

[492] To ensure consistency in the use of terms in this Final Rule, Cost Allocation Principle 3 as stated in the Proposed Rule has been changed to refer to facilities ''selected'' in a regional transmission plan, ability of a ''public utility transmission provider in a transmission planning region'' to use a benefit to cost threshold, and potential Commission approval of a ''higher'' ratio.

[493] The phrase ''net benefits to qualify for interregional cost allocation'' differs from the language in regional cost allocation Principle 3 because there is no plan at the interregional level for which projects would be selected. The word ''large'' was changed to ''high'' to be consistent with the language in regional cost allocation Principle 3.

being constructed. As such, the Commission finds (and several commenters agree) that a benefit to cost ratio of 1.25 to 1 to be a reasonable ratio that will not act as a barrier to the development and construction of valuable new transmission projects. Furthermore, regarding comments requesting that the Commission decline to establish a benefit to cost threshold given the difficulty in quantifying benefits, we reiterate that the benefit to cost ratio threshold identified in this Final Rule applies only if the public utility transmission providers of a transmission planning region choose to use a benefit to cost ratio to determine which transmission facilities are selected in the regional transmission plan for purposes of cost allocation. They may decide to have no benefit to cost ratio threshold greater than one at all.

650. Furthermore, in response to MISO Transmission Owners, if the issue of whether any benefit to cost ratio threshold for an interregional transmission facility may supersede the ratio for a transmission planning region's regional transmission cost allocation should be presented to us on compliance, we will address it then based on the specific facts in that filing.

5. Cost Allocation Principle 4—Allocation to be Solely Within Transmission Planning Region(s) Unless Those Outside Voluntarily Assume Costs [494]

a. Comments

651. Nearly all entities that commented on proposed Cost Allocation Principle 4 support it.[495] For example, NEPOOL states that it particularly supports Principle 4, citing New England's successful history of voluntarily planning, developing and allocating the costs of interregional projects with its neighbors. New York ISO agrees, stating that it would be appropriate to allow more expansive voluntary cost allocation arrangements, but would be premature and unrealistic to require all regions to adopt specific cost allocation methodologies on an *ex ante* basis that would be applicable to future situations as yet unknown.

652. However, some commenters raise specific concerns. East Texas Cooperatives argue that the restriction on the involuntary allocation of costs on an interregional basis should not be interpreted to prevent a transmission provider from proposing methods to capture the costs associated with the benefits enjoyed by exported energy. MISO Transmission Owners agree with this argument. The New England States Committee on Electricity states that interregional Principle 4 aligns with its view that any allocation method must not transfer costs to New England ratepayers to support development of facilities outside New England unless New England concludes that development of such facilities are the most cost-effective. Northeast Utilities states that it supports the principle in so far as it limits the allocation of costs for interregional projects only to facilities located within neighboring regions.

653. Other commenters argue that the Commission should not limit the application of interregional cost allocation requirements to interregional projects, suggesting that transmission facilities located solely within one region may have benefits in other regions.[496] NextEra recommends modifying Principle 4 so that if transmission facilities within one region clearly benefit another region, the Commission would allow cost recovery by the transmission providers in the region providing the benefits to the other. NextEra maintains that without such a mechanism, the benefitting region would receive a windfall. According to PJM, basing the cost allocation on physical location rather than analyzing power flows, reduced congestion, or improved reliability, is untenable, would invite gaming of the routing and siting process to drive particular cost allocation results, would make negotiations on cost allocation among neighbors more difficult, is inconsistent with a beneficiary pays approach, and is contrary to the existing PJM–MISO interregional cost allocation method. As an alternative, PJM suggests providing for the cost allocation of transmission to all system users that benefit from the increased transfer capability that the new facility provides, thereby moving the decision from controversies surrounding particular generation sources to the future characteristics of the transmission system, which is a subject that is more clearly within the Commission's authority and expertise.

654. Similarly, MISO seeks clarification that two or more regions may mutually designate transmission facilities located entirely within a single region as an interregional transmission facility and allocate costs accordingly, which is the approach taken in the current cross-border cost sharing arrangement between MISO and PJM. MISO, along with MISO Transmission Owners, argues that projects located entirely in one region may provide benefits to entities in the neighboring region.

655. Large Public Power Council states that its members cannot at this time commit to entering into interregional agreements regarding cost allocation. It notes that its members are creatures of state and municipal governments, and their authority to enter into binding arrangements is restricted.

656. Finally, the Coalition for Fair Transmission Policy sees an ambiguity in the Proposed Rule. It states that the Proposed Rule allows for costs to be allocated to a beneficiary even when the beneficiary has not entered into a voluntary arrangement to pay those costs, but proposed Cost Allocation Principle 4 states that costs cannot be allocated to an entity or region outside of the geographic boundaries of the planning region where the project is being constructed, absent a voluntary agreement.

b. Commission Determination

657. The Commission adopts the following Cost Allocation Principle 4 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 4: The allocation method for the cost of a transmission facility selected in a regional transmission plan [497] must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region.[498]

and

> Interregional Cost Allocation Principle 4: Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the

[494] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[495] *E.g.,* ISO New England; Nebraska Public Power District; NEPOOL; New York ISO; New York PSC; Northern California Power Agency; and New York Transmission Owners.

[496] *See, e.g.,* NextEra; MISO; and MISO Transmission Owners.

[497] The phrase ''an intraregional facility'' was replaced with ''a transmission facility selected in a regional transmission plan'' to be consisted with P 0–0 n this Final Rule.

[498] At the end of the sentence, ''entities'' has been changed to ''beneficiaries'' to be precise. Slight wording changes have been made to the last sentence in this regional cost allocation Principle 4 and interregional cost allocation Principle 4 to clarify the point being made.

transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located.[499] However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.[500]

658. Regarding the allocation of the cost of a transmission facility that is located entirely within one transmission planning region and that is intended to export electric energy from that transmission planning region to another transmission planning region, the public utility transmission providers in the exporting transmission planning region may not have a regional cost allocation method or methods pursuant to this Final Rule that assigns some or all of the cost of that transmission facility to beneficiaries in another transmission planning region without reaching an agreement with those beneficiaries. The public utility transmission providers in such transmission planning regions may, however, negotiate an agreement to share the transmission facility's costs with the beneficiaries in another transmission planning region, as they always have been free to do. Doing so is not inconsistent with Regional Cost Allocation Principle 4.

659. Regarding the allocation of the cost of an interregional transmission facility that is located in two or more neighboring transmission planning regions and that is intended to export electric energy from one such transmission planning region to the other transmission planning region, this Final Rule requires that the public utility transmission providers in each pair of transmission planning regions have an interregional cost allocation method or methods for sharing the cost of such transmission facilities. However, Interregional Cost Allocation Principle 4 does not permit the cost allocation method or methods for those two transmission planning regions to assign the cost of the transmission facility to beneficiaries in a third transmission planning region except where the beneficiaries in the third transmission planning region voluntarily reach an agreement with the two transmission planning regions in which the transmission line is located. They also may satisfy the requirements of this Final Rule by having an interregional cost allocation method or methods for more than two transmission planning regions, although this Final Rule does not require them to do so.

660. We decline to adopt NextEra's recommendation that we modify Principle 4 to allow cost allocation by the public utility transmission providers in one transmission planning region to beneficiaries in another transmission planning region.[501] We acknowledge that this Final Rule's approach may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility. Nonetheless, the Commission finds this approach to be appropriate. For the reasons discussed herein, we are establishing a closer link between regional transmission planning and cost allocation, both of which involve the identification of beneficiaries. In light of that closer link, we find that allowing one region to allocate costs unilaterally to entities in another region would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. Indeed, if the Commission expected such participation, the resulting regional transmission planning processes would amount to interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner. The Commission is not requiring either interconnectionwide planning or interconnectionwide cost allocation.

661. MISO's and PJM's comments raise a similar issue that our proposed reforms inappropriately limit interregional cost allocation to those beneficiaries that are physically located in the transmission planning region in which the transmission facility is located. We find that this approach would raise the same concerns discussed immediately above.

662. We recognize that MISO and PJM have an existing cross-border cost allocation method that permits them, in certain cases, to allocate to one RTO the cost of a transmission facility that is located entirely within the other RTO, even if the facility does not cross the border between their two regions. Because MISO and PJM developed their cross-border allocation method in response to Commission directives related to MISO and PJM's intertwined configuration, we find that MISO and PJM are not required by this Final Rule to revise their existing cross-border allocation method in response to Cost Allocation Principle 4. If MISO and PJM believe their existing cross-border cost allocation method fulfills other principles discussed herein, they may explain that in the filings they make in compliance with this Final Rule.

663. In response to Large Public Power Council, as we discuss below,[502] a non-public utility transmission provider seeking to maintain a safe harbor tariff must ensure that the provisions of that tariff substantially conform, or are superior to, the *pro forma* OATT as it has been revised by this Final Rule. However, it remains up to each non-public utility transmission provider whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.

664. We disagree with Coalition for Fair Transmission Policy's argument that there is an ambiguity in our reforms that allows for costs to be allocated to a beneficiary when the beneficiary has not entered into a voluntary arrangement to pay those costs, while also providing in Cost Allocation Principle 4 that the costs of transmission facilities in a regional transmission plan cannot be allocated to an entity in another transmission planning region, absent a voluntary agreement.

6. Cost Allocation Principle 5—Transparent Method for Determining Benefits and Identifying Beneficiaries[503]

a. Comments

665. Nearly all commenters that address this proposed principle supported it.[504] PSEG Companies agree

[499] The first two sentences of interregional cost allocation Principle 4 differ from regional cost allocation Principle 4 because at the interregional level, there may be a scenario where a transmission facility is located in one transmission planning region but provides benefits to another transmission planning region. For example, if regions A and B plan an interregional transmission facility that they believe benefits region C, regions A and B cannot allocate costs of that facility to region C involuntarily.

[500] "Transmission facility" was changed to "upgrade" in each instance in this sentence to make it consistent with the last sentence in regional cost allocation Principle 4. The end of the last sentence is revised to be consistent with Regional Cost Allocation Principle 4.

[501] *See* discussion *supra* section IV.D.

[502] *See* discussion *infra* section V.B.

[503] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[504] *E.g.,* SPP; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

that there is a need for transparent cost allocation and that customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. Further, PSEG Companies state that it should be clear which customers are benefiting from and paying for system upgrades before they are built, as this will minimize after-the-fact debates and litigation.

666. Some commenters that support the principle caution that it will be difficult to determine costs and benefits with mathematical precision.[505] In light of such difficulties, Connecticut & Rhode Island Commissions suggest that transmission cost allocation methods be pragmatic. DC Energy raises concerns about the use of biased assessments, and it suggests that one method for improving the reliability of cost-benefit analyses is to require that only direct costs and benefits be considered in economic studies since they offer greater certainty. PSEG Companies agree with the proposed principle and suggest that for non-reliability projects, there should be a more definitive link between identified beneficiaries and the costs to be paid.

667. Several commenters raise specific issues with respect to the proposed principle. Transmission Dependent Utility Systems urge the Commission to recognize that transparency alone is insufficient without load serving entity involvement in the planning and development of the cost allocation method. Finally, MISO Transmission Owners argue that current RTO processes provide significant transparency.

b. Commission Determination

668. The Commission adopts the following Cost Allocation Principle 5 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

and

Interregional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility.[506]

669. Requiring cost allocation methods and their corresponding data requirements for determining benefits and beneficiaries to be open and transparent ensures that such methods are just and reasonable and not unduly discriminatory or preferential. Furthermore, greater stakeholder access to cost allocation information will help aid in the development and construction of new transmission, as stakeholders will be able to see clearly who is benefiting from, and subsequently who has to pay for, the transmission investment. In addition, the Commission agrees that such access to information may avoid contentious litigation or prolonged debate among stakeholders.

670. As the Commission stated in the Proposed Rule, we recognize that identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. However, the Commission finds that a transparent transmission planning process is the appropriate forum to address these issues, and by addressing these issues, there will be a greater likelihood that regions can build the new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

671. We acknowledge the concerns that the method or methods for determining benefits and beneficiaries must balance being pragmatic and implementable with being accurate and unbiased. Cost Allocation Principle 5 requires that the method or methods be known and transparent. As stakeholders participate in the development of such methods, their input should ensure that the method or methods ultimately agreed upon is balanced and does not favor any particular entity. In developing this method or methods, public utility transmission providers and their stakeholders are also free to consider suggestions, such as those made by DC Energy, that only direct costs and benefits should be considered in economic studies. We will not, however, opine on such suggestions at this time. Rather, the Commission will review such matters once the cost allocation method or methods are filed on compliance.

672. In response to MISO Transmission Owners, the Commission declines at this time to rule on whether any current RTO and ISO processes provide enough transparency to satisfy Cost Allocation Principle 5. Such determinations will be made upon the submittal of a compliance filing by any RTO or ISO.

7. Cost Allocation Principle 6—Different Methods for Different Types of Facilities[507]

a. Comments

673. Many commenters generally support proposed Cost Allocation Principle 6, arguing that transmission projects are built for different purposes, such as for reliability or economic reasons, and different methods may therefore be appropriate.[508] Four G&T Cooperatives state that the planning regions should be given latitude to determine within reason the range of benefits that can be considered for cost allocation purposes, as well as the prioritization and relative value of such benefits. Pennsylvania PUC contends that cost allocation methods should maintain stable transmission rates that will be preferable both to the customers who pay the rates and the system planners who have to forecast future expenditures for the system. It argues that a cost allocation method should be flexible enough to accommodate different types of renewable energy from a diversity of sources, public policy changes, and potential shifts from older fossil fuel generation and development of other energy sources such as nuclear generation. Pennsylvania PUC also suggests that a cost allocation method be able to accommodate different types of facilities such as those serving renewable and non-renewable generators, both economic and reliability projects, as well as specialized projects such as generator interconnection facilities. MISO Transmission Owners agree and state that the applicable method should be determined through the stakeholder planning process. Dayton Power & Light states that one method may be appropriate, such as the beneficiary-pays approach, but the method by which beneficiaries are identified may depend on the type of project involved. New Jersey Board also supports flexibility and states that further analysis must be completed to

[505] *E.g.,* NextEra and Sunflower and Mid-Kansas.

[506] ''Interregional'' has been added before ''transmission facility'' at the end of the sentence to be precise.

[507] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[508] *E.g.,* Indianapolis Power & Light; NEPOOL; Public Power Council; Northeast Utilities; New Jersey Board; E.ON; American Transmission; Dayton Power and Light; Delaware PSC; Dominion; New England States Committee on Electricity; and PSEG Companies.

determine how best to allocate costs for transmission driven primarily by public policy requirements because the beneficiaries may differ markedly from the beneficiaries of transmission facilities built for reliability purposes.

674. PSEG Companies request that reliability and non-reliability projects be treated differently for cost allocation purposes, and they advocate adopting a voting mechanism for economic projects that would require that proposed economic upgrades be voted on by the entities that have been deemed to benefit from them and who in turn would be responsible for paying for them. National Grid, however, is concerned about the use of supermajority voting requirements for economic transmission projects. In response, Con Edison points favorably to New York ISO's supermajority voting requirements for economic transmission projects in its transmission planning process.

675. In its reply comments, PJM proposes a possible way to reconcile what it views as competing directives in the Proposed Rule regarding transmission planning and cost allocation related to economic, reliability, and public policy projects. Economic and reliability projects would be included in one category, under which a beneficiary pays approach would match the planning purposes used (*e.g.,* avoiding a violation of a reliability standard). Public policy projects would comprise the second category, under which the Commission would align the planning and cost allocation for such projects with regional action taken by states sharing similar public policy objectives. PJM suggests that regions could form interstate compacts to identify shared public policy goals and resource requirements and accept the allocation of costs associated with those projects. PJM further suggests a ''safe harbor'' to prevent states from having to absorb costs for public policy projects undertaken in other states.

676. Large Public Power Council believes that the interregional allocation of costs is a topic on which consensus is feasible only in the context of specific projects proposed by project developers to satisfy identified market needs.

677. Some commenters point to existing approaches as being adequate to meet this principle. Northeast Utilities states that a comprehensive approach using the current New England method should be appropriate. Northeast Utilities contends that the existing cost allocation rules in the ISO-New England OATT would meet the proposed requirements for regional cost allocation with the addition of a clearer cost allocation method for economic projects and a separately stated method for projects intended to meet public policy requirements.

678. Some commenters are concerned as to whether the Commission should allow different cost allocation methods for different facilities.[509] These commenters make several arguments: (1) New transmission facilities seldom serve one function and may provide general reliability and other benefits to the transmission system; (2) the benefits of a given project may vary over time; and (3) such designations have been the source of substantial delays and conflict as planning participants spend time and resources arguing over a project's designation.

679. Xcel states that while it does not oppose the concept of using different cost allocation mechanisms for projects with different drivers, it believes that an excessive amount of time is being spent splitting benefits into their component buckets. It argues that the appropriate focus of cost allocation methods instead should be determining the multiple benefits that any transmission projects provide to a planning region and its stakeholders. Xcel explains that one objective of the state transmission certification process is to ensure that, regardless of the initial driver, projects are ultimately scoped and right-sized to provide multiple benefits. Xcel thus argues that cost allocation methods should concentrate on identifying and measuring multiple benefits that transmission facilities provide, rather than developing a new cost allocation method for each initial project driver.

680. Multiparty Commenters express concern that there could be a proliferation of cost allocation designs if the Commission allows different cost allocation methods for different types of facilities and for interregional and regional planning processes. They believe that this will lead to protracted disputes about the function of a transmission facility.

681. Transmission Dependent Utility Systems believe that Cost Allocation Principle 6 could place too much discretion in the hands of the transmission providers, particularly in non-RTO/ISO regions, and they urge the Commission to require transmission providers to make these decisions in collaboration with customers. They state that including load serving entities in these discussions would go a long way towards alleviating their concern with having a separate cost allocation method for facilities driven by public policy requirements.

[509] *E.g.,* ITC Companies; Multiparty Commenters; NextEra; and Wind Coalition.

682. Several commenters seek clarification of Principle 6. New York ISO seeks clarification that public utility transmission providers may adopt cost allocation methods for different types of transmission projects without creating a specific cost allocation mechanism applicable solely to public policy projects. New York ISO states that the Proposed Rule appears to contemplate this and contends that such a clarification would be appropriate, especially for regions such as New York that do not currently have a rule requiring that public policy projects be constructed. New York ISO states that such cost allocation methods can and should be determined on a project-specific basis depending on the policy driving the agreed-upon transmission project.

683. Long Island Power Authority suggests that imposing a single regional cost allocation method for public policy driven projects may inhibit the development of transmission that facilitates the interconnection of renewable energy generation and would allocate costs of each public policy driven project to the same beneficiaries, leading to the assignment of duplicative costs to specific entities and to increases in rates that reduce, or possibly eliminate, an entity's ability to incur costs for its own renewable generation or energy efficiency goals. Long Island Power Authority therefore believes the Final Rule should not direct project costs to non-beneficiaries and not impose costs that prevent non-jurisdictional entities from satisfying their own lawful public policy goals.

684. Alliant Energy seeks clarification that for purposes of Principle 6 the terms ''region'' and ''regional'' cover the entire RTO or ISO footprint in the case where there is a Commission-approved planning region within an RTO or ISO, such as American Transmission within MISO. Alliant Energy contends that Principle 6 invites the opportunity for discrimination and unintended consequences if the Commission determines that a region could constitute a single transmission provider within the RTO or ISO footprint. It states that cost allocation policies within an RTO or ISO footprint must be consistent.

b. Commission Determination

685. The Commission adopts the following Cost Allocation Principle 6 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 6: A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.[510] Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.

and

Interregional Cost Allocation Principle 6: The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.[511] Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.[512]

686. We agree with the Pennsylvania PUC and others that transmission planning regions should be afforded the opportunity to develop a different cost allocation method for different transmission project types.[513] The development of such cost allocation method, however, rests with the public utility transmission providers participating in regional transmission planning processes in consultation with stakeholders. Cost Allocation Principle 6 permits but does not require the public utilities in a transmission planning region to designate different types of transmission facilities, and it permits but does not require the public utilities in a transmission planning region that choose to designate different types of transmission facilities to have a different cost allocation method for each type. However, we clarify that if the public utilities choose to have a different cost allocation method for each type of transmission facility, there can be only one cost allocation method for each type.

687. It may be appropriate to have different cost allocation methods for transmission facilities that are planned for different purposes or planned pursuant to different regional transmission planning processes, provided that these methods are applied consistently. In particular, in response to some commenters, we clarify that we are not requiring a distinct regional or interregional cost allocation method applicable solely to transmission facilities for Public Policy Requirements and that are selected in a regional transmission plan for purposes of cost allocation, but we allow it.

688. Moreover, as the Commission recognized in Order No. 890, states have a critical role with respect to transmission planning.[514] That role may be particularly important with respect to planning for transmission needs driven by Public Policy Requirements, where multiple states may be impacted by the selection (or cost) of a given transmission project needed to meet transmission needs driven by a particular state's Public Policy Requirement. Therefore, we strongly encourage states to participate actively not only in transmission planning processes in general, but specifically in the identification of transmission needs driven by Public Policy Requirements. We also note that agreements among states with respect to cost allocation may be particularly important for transmission facilities designed to meet transmission needs driven by Public Policy Requirements. States could pursue such agreements in various forms, including a committee of state regulators or through a compact among states that receives appropriate approval from Congress.

689. We leave it to each transmission planning region or pair of transmission planning regions to propose on compliance whether, and how, to distinguish between types of transmission facilities. We also note that a public utility transmission provider together with other public utility transmission providers in a transmission planning region, and an RTO or ISO, which is itself a public utility transmission provider, may have a single cost allocation method for all proposed transmission facilities or different methods for different types of transmission facilities. For example, cost allocation methods may distinguish among transmission facilities that are driven by needs associated with maintaining reliability, addressing economic considerations, and achieving Public Policy Requirements, all of which would be required to be considered in the regional transmission planning process as explained in this Final Rule. The Commission recognizes that several transmission planning regions that have different cost allocation methods by type of transmission project currently have transmission planning procedures and cost allocation methods that refer only to the first two types of transmission projects. This Final Rule allows a public utility transmission provider through its participation in a transmission planning region to distinguish or not distinguish among these three types of transmission facilities, as long as each of the three types is considered in the regional transmission planning process and there is a means for allocating the costs of each type of transmission facility to beneficiaries. In response to PSEG Companies, we clarify that a regional cost allocation method for one type of regional transmission facility or for all regional transmission facilities may include voting requirements for identified beneficiaries to vote on proposed transmission facilities.

690. However, a public utility transmission provider must have a regional cost allocation method for any transmission facility selected in a regional transmission plan for purposes of cost allocation. It may not designate a type of transmission facility that has no regional cost allocation method applied to it, which would effectively exclude that type of transmission facility from being selected in a regional transmission plan for purposes of cost allocation. In response to New York ISO and Long Island Power Authority, a transmission facility proposed to address a Public Policy Requirement must be eligible for selection in a regional transmission plan for purposes of cost allocation and must not be designated as a type of transmission facility for which the cost allocation method must be determined only on a project-specific basis. However, in contrast to what New York ISO's comment implies, the regional cost allocation method for such a transmission facility may take into account the transmission needs driven by a Public Policy Requirement, who is responsible for complying with that Public Policy Requirement, and who benefits from the transmission facility. If a regional transmission plan determines that a transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.

691. As stated elsewhere, we decline to opine here on whether any existing processes satisfy Cost Allocation Principle 6 in the regional and

[510] ''Public Policy Requirements'' replaces ''public policy requirements established by State or Federal laws or regulations that may drive transmission needs'' as defined in P 0 of this Final Rule.

[511] ''Public Policy Requirements'' replaces ''public policy requirements established by State or Federal laws or regulations that may drive transmission needs'' as defined in P 0 of this Final Rule.

[512] The word ''clearly'' has been added to this sentence to make it consistent with the last sentence in regional cost allocation Principle 6.

[513] We note that a method, such as a highway-byway method for a reliability project, may itself further distinguish types of facilities, for example by voltage, and allocate costs differently for each type.

[514] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.

interregional context. For example, if a region believes that its regional transmission planning process meets Regional Cost Allocation Principle 6 for all facilities, including transmission facilities driven by a Public Policy Requirement, it may submit evidence in support of this position in a compliance filing pursuant to this Final Rule.

692. Some commenters are concerned that designation of transmission facility type can result in substantial delay because transmission facilities may serve multiple functions and benefits and beneficiaries may vary over time. This concern should be addressed in each region's transmission planning process. However, we note that many regional transmission planning processes currently have mechanisms for distinguishing between types of transmission facilities, and there is no reason to believe that transmission facilities designation necessarily results in a substantial delay.

693. In response to Alliant Energy's comment, the Commission addressed this concern in the regional transmission planning section above.[515]

8. Whether To Establish Other Cost Allocation Principles

a. Commission Proposal

694. The Proposed Rule sought comment on whether additional principles should apply to cost allocation for either regional or interregional transmission facilities, and it asked commenters to submit and explain the need for those principles.[516]

b. Comments

695. Six Cities ask the Commission to include a new principle or a corollary requirement that the transmission planning processes include provisions to encourage cost containment, a point echoed in other comments on cost allocation.[517] The New England States Committee on Electricity also argues that the Commission should establish transmission cost control and review mechanisms to ensure that construction is performed as efficiently as possible and the costs incurred are reasonable.

696. ELCON and Associated Industrial Groups urge the Commission to adopt two technical principles related to the costs of new transmission investments being allocated on a representatively-determined capacity (MW) basis, not on an volumetric (MWh) basis and periodic adjustment of cost allocation to reflect changes in power flows.[518] However, ITC Companies do not support periodic adjustments of cost allocation and describe it as disruptive and potentially risky.

697. Other commenters propose principles that look to safeguard particular participants in the transmission planning process. For example, City of Los Angeles Department of Water and Power states that there should be appropriate safeguards that allow non-public utilities to seek required approvals before they are allocated costs for new transmission projects, and that participation in the regional transmission planning process by non-public utilities remain voluntary. Similarly, Transmission Dependent Utility Systems state that if a particular customer is not allowed to participate fully in a regional planning process, there should be a presumption that the customer is not receiving benefits from the regional plan.

698. San Diego Gas & Electric proposed policy changes for transmission projects that span multiple balancing authority areas and for which a voluntarily negotiated cost allocation arrangement proves feasible. Its proposed policy changes focused on payment by loads, allocation of costs to balancing authority areas that do or do not benefit, and encouragement for non-jurisdictional governmental agencies to adopt reciprocal cost allocation policies.

699. Michigan Citizens Against Rate Excess proposed three additional principles that limit transmission costs driven by public policy requirements to the state or states of origin,[519] that transmission cost recovery should not be a means to subsidize non-transmission projects, and that no state or region should shoulder the cost alone when benefits accrue to others as well, namely for reliability projects only.

700. PUC of Ohio maintains that the Commission should consider principles when considering any long-term transmission rate design that provide the utility the opportunity to recover an authorized revenue amount, is equitable, provides for customer understanding and rate continuity, minimizes customer impact and undue cost shifts, and recognizes the use and benefits of the transmission system.

701. Environmental Defense Fund, the Wilderness Society, and Western Resource Advocates recommended principles that they argue will assist in identifying the full range of benefits that must be accounted for when justifying a project.[520] They state that project costs should be allocated consistent with the range/distribution of benefits that are likely to accrue in both the near- and long-term, that the benefits of projects must include carbon emissions reductions and the attainment of other state and federal policy imperatives, and that beneficiaries under any beneficiaries-pay cost allocation policy be defined to include consideration of the myriad of beneficial outcomes described above, as well as other benefits likely to accrue to transmission system users over the life of the grid investment.

702. American Antitrust Institute states that the Commission should consider how cost-benefit tests for cost allocation and recovery can be designed to promote competition and encourages the Commission to carefully scrutinize cost allocation approaches based on voting rules that give incumbent utility transmission providers the ability to vote against economic transmission projects that benefit ratepayers.

703. Energy Consulting Group suggests that beneficiaries, including those receiving firm transmission service should to be obligated to pay the allocated costs of the improvements through a specified tariff rate and relieved of any obligations to pay current OATT rates for improvements.

c. Commission Determination

704. We agree with Six Cities, New England States Committee on Electricity, and others that cost containment is important. However, we decline to establish a corresponding cost allocation principle as recommended, primarily because cost containment concerns the level of costs, not how costs should be allocated among beneficiaries. While we understand and agree that those receiving a cost allocation are appropriately concerned

[515] *See* discussion *supra* section III.A.

[516] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 178.

[517] *E.g.,* California Commissions; California Municipal Utilities; City of Santa Clara; Connecticut & Rhode Island Commissions; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; Northeast Utilities; Northern California Power Agency; and Transmission Agency of Northern California. While San Diego Gas & Electric agrees that it is appropriate for commenters to seek safeguards with respect to cost overruns, it takes issue as a factual matter with California Municipal Utilities' inclusion of the Sunrise-Powerlink project as one that is a clear example that cost overruns are endemic.

[518] *See also* East Texas Cooperatives and Maine Parties.

[519] *See also* Electricity Consumers Resource Council and the Associated Industrial Groups and Public Power Council.

[520] *E.g.,* Environmental Defense Fund; Wilderness Society; and Western Resource Advocates. Sonoran Institute also proposes the second and third principles proposed by Environmental Defense Fund and Wilderness Society and Western Resource Advocates.

that the level of the cost being allocated should be controlled accordingly, we do not believe that a new principle or corollary requirement in this Final Rule is the appropriate mechanism to promote cost containment.

705. We have considered all the other additional principles proposed by commenters but decline to adopt them. We do not believe that any additional principles are necessary at this time. Moreover, we believe that many of the suggestions of commenters, if required by this Final Rule, would limit the flexibility we provide in this Final Rule for public utility transmission providers to propose the appropriate cost allocation method or methods for their transmission planning region or pair of transmission planning regions. If a commenter believes that one or more of its suggestions is consistent with the six principles we adopt herein, that commenter is free to work within a regional stakeholder process to see if its concerns could be addressed. We will permit each transmission planning region or pair of transmission planning regions to propose cost allocation methods that satisfy additional requirements that they deem necessary to meet the specific needs of that transmission planning region or transmission planning regions provided they are consistent with the cost allocation principles of this Final Rule. Any such requirements should be submitted as part of the cost allocation method or methods on compliance, along with an explanation of how they comply with the requirements of this Final Rule.

F. Application of the Cost Allocation Principles

706. The Proposed Rule addressed several potential applications of the cost allocation principles, seeking general comment on the appropriateness of these six cost allocation principles and how they should be applied to the costs of new regional and interregional transmission facilities that are eligible for cost allocation.[521]

1. Whether To Have Broad Regional Cost Allocation for Extra-High Voltage Facilities

a. Commission Proposal

707. The Commission declined in the Proposed Rule to address in the abstract and in the absence of a record whether several candidate cost allocation methods, either in use today in a region or proposed by some commenters, would satisfy the proposed regional and interregional cost allocation principles.

b. Comments on Cost Allocation for Extra-High Voltage Facilities

708. Several commenters recommend that the Commission establish a rebuttable presumption that the costs of extra-high voltage transmission facilities be allocated widely across a region.

709. NextEra argues that extra-high voltage lines, typically 345 kV and above, provide regional benefits, and that the Commission should require that every cost allocation method include a rebuttable presumption that the costs of such lines will be allocated widely. WIRES agrees, pointing out that this is essentially the approach taken in PJM for projects above 500 kV. NextEra suggests that those seeking to rebut this presumption in the context of a particular extra-high voltage project should bear the burden of showing they receive no benefits from the project. To accomplish this, NextEra recommends that the Commission adopt a *pro forma* transmission cost allocation method, and that transmission providers and stakeholders could either follow the *pro forma* model or propose a method that is consistent with or superior to that model. Multiparty Commenters also support a rebuttable presumption for extra-high voltage lines.[522] Similarly, AEP argues that extra-high voltage facilities provide regionwide benefits and the costs of such facilities should be allocated widely across a region. AEP also suggests that extra-high voltage AC facilities that interconnect electrical regions and that are identified as needed under the applicable interregional coordination agreement benefit both regions, and AEP states that the costs of such facilities should be allocated across those regions. Clean Line supports allocating the costs for extra-high voltage lines across the largest region possible.

710. Baltimore Gas & Electric submits that the Final Rule should apply highway/byway principles to projects that traverse RTOs and to projects within RTOs. It states that the cost allocation principles espoused in the Proposed Rule should be adopted, and that the Commission should at least allow for the Opinion No. 494 method to be continued in PJM,[523] regardless of the methods that are deemed appropriate for other RTOs.[524] However, Baltimore Gas & Electric states that other RTOs must maintain cost allocation mechanisms with respect to each other that provide for reciprocal treatment. It states that new, high voltage, RTO-approved facilities should be paid for uniformly by all rate zones because they provide significant benefits to all rate zones.

711. Several reply commenters oppose proposals to establish a rebuttable presumption for extra-high voltage facilities.[525] Large Public Power Council argues that such proposals cannot be squared with the cost allocation principle set forth in *Illinois Commerce Commission* that utilities cannot be required to pay for facilities from which its members derive no or only trivial benefits. Ad Hoc Coalition of Southeastern Utilities replies that there is no basis to presume that an extra-high voltage transmission overlay is beneficial to all customers, and that such a position is inconsistent with *Illinois Commerce Commission*. Ad Hoc Coalition of Southeastern Utilities emphasizes that the addition of extra-high voltage facilities can overload the underlying transmission system and change power flows, requiring upgrades to lower voltage lines and operational changes. Ad Hoc Coalition of Southeastern Utilities contends that broadly socializing the costs of extra-high voltage facilities could bias the integrated resource planning process total-cost analyses toward such facilities in that at least some of their costs will be spread throughout the region and not incurred by the utility causing the need for the facilities. Similarly, Southern Companies states that its integrated resource planning has not shown that extra-high voltage lines are a cost-effective, reliable solution to meeting identified transmission needs and that constructing such lines in the Southeast and then broadly socializing their costs over the entire load in the region would result in higher costs to consumers than implementing non-extra-high voltage solutions. Southern Companies also argue that such an approach would skew the evaluations of which transmission and non-transmission

[521] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 178.

[522] Multiparty Commenters append an analysis performed by CRA International that purports to show the widely dispersed benefits of extra-high voltage transmission facilities (CRA Study).

[523] *PJM Interconnection, L.L.C.,* Opinion No. 494, 119 FERC ¶ 61,063 (2007), Opinion No. 494–A, 112 FERC ¶ 61,082 (2008) (cost allocation methods for new transmission facilities that distinguished between facilities below and above 500 kV), *remanded, Illinois Commerce Comm'n* v. *FERC,* 576 F.3d 470 (7th Cir. 2009).

[524] Delaware PSC and American Forest & Paper also support PJM's cost allocation method for high voltage facilities. American Forest & Paper asserts PJM's method is preferable to the energy allocator method proposed in MISO.

[525] *E.g.,* Coalition for Fair Transmission Policy; Ad Hoc Coalition of Southeastern Utilities; Southern Companies; Large Public Power Council; East Texas Cooperatives; New England States Committee on Electricity; and APPA.

alternatives are the least cost means to meet an identified need. MEAG Power provides illustrations of how such a proposal could result in unjust and unreasonable rates. Coalition for Fair Transmission Policy argues that the CRA Study filed by Multiparty Commenters is flawed because it neglects to mention that in some cases extra-high voltage facilities impose costs on some parts of a region as well, and that such impacts can be ascertained only by examining specific projects. MEAG Power similarly asserts that the CRA study is flawed for a number of reasons, including the fact that it examines only the existing grid, omits several regions from its analysis and fails to estimate any dollar benefits accruing to any party.

712. In addition, in its reply comments, SoCal Edison disagrees with NextEra's proposal for a *pro forma* cost allocation agreement, arguing that there is not sufficient evidence to determine that such an approach is consistent with the principle that costs be allocated roughly commensurate with benefits.

c. Commission Determination

713. We are not persuaded to adopt a rebuttable presumption that the costs of extra-high voltage facilities, such as 345 kV and above, should be allocated widely across a transmission planning region. Such a presumption would be akin to a default cost allocation method which, as discussed above,[526] we do not adopt. For the same reason, we do not agree that a *pro forma* cost allocation method is appropriate.

714. The Commission recognizes and intends that several approaches to cost allocation may satisfy the principles adopted in this Final Rule. If it were otherwise, the offer of regional flexibility would be an empty offer. Therefore, we do not impose a single cost allocation method for any transmission planning region. If public utility transmission providers and their stakeholders in a transmission planning region reach a consensus that the costs of extra-high voltage facilities, such as 345 kV and above, should be allocated widely and that this would result in a distribution of costs that is at least roughly commensurate with the benefits received, and support this conclusion with evidence, they may submit the method to the Commission on compliance.

[526] *See* discussion *supra* section IV.E.1.

2. Whether To Limit the Use of Participant Funding

a. Commission Proposal

715. Following the presentation of these six cost allocation principles in the Proposed Rule, the Commission discussed their application to participant funding as a regional or interregional cost allocation method for satisfying these principles. The Commission explained that in transmission planning regions outside of the RTO and ISO footprints, many of the cost allocation methods that the Commission accepted in the Order No. 890 compliance proceedings rely exclusively on a ''participant funding'' approach to cost allocation, in which the costs of a new transmission facility are allocated only to entities that volunteer to bear those costs.[527] The Commission proposed that participant funding is not a cost allocation method that would satisfy these principles. The Commission further noted that a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. However, the Proposed Rule did not prohibit voluntary participant funding for those that choose to use it.

b. Comments on Limiting Participant Funding

716. Many commenters generally agree that a cost allocation method based exclusively on a participant funding approach neither achieves the goal of timely development of building transmission facilities nor results in just and reasonable rates.[528] In support of this position, several commenters maintain that participant funding does not allocate the costs of new regional transmission projects to their multiple beneficiaries.[529] East Texas Cooperatives request that the Commission define the scope of acceptable benefits that may be considered, provide that cost allocation methods ensure that customers receive benefits commensurate with their share of costs, and conclude that participant funding is a failed cost allocation method.

[527] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 121–28.

[528] *E.g.*, AWEA; East Texas Cooperatives; Gaelectric; ITC Companies; Multiparty Commenters; NextEra; Transmission Access Policy Study Group; Transmission Dependent Utility Systems; and WIRES.

[529] *E.g.*, AWEA; Gaelectric; Multiparty Commenters; and Transmission Dependent Utility Systems.

717. Several commenters agree that the Commission should clarify what regional cost allocation approaches are not acceptable.[530] AWEA states that to ensure that future cost allocation proposals do not serve as barriers to transmission expansion, and can support transmission additions that are ''right sized'' to meet the long-term needs of the system, the Commission should specify when participant funding, and other such cost allocation methods, should not be allowed, or what level of participant funding it might find acceptable. NextEra argues that the use of participant funding should be minimized, and that the Final Rule should specify that costs of transmission projects identified through the transmission planning process cannot be allocated to generators because any other outcome would simply continue the status quo of discouraging development of new resources.

718. In contrast, other commenters argue that the Commission should promote flexibility, and continue to allow for participant funding of projects with voluntary agreements on cost sharing.[531] Some commenters appear to believe the Proposed Rule would prohibit the use of participant funding in all circumstances, not just for new transmission facilities in a regional transmission plan for purposes of regional cost allocation to regional beneficiaries. As a starting point, a few commenters state that the Commission has accepted and continues to accept rates using participant funding. For example, E.ON points out that the Commission approved negotiated rates for the Chinook and Zephyr merchant transmission projects, which it believes is evidence that participant funding may be of practical use and may have more widespread application as transmission customers are required to access electricity from renewable generation. Therefore, some commenters argue that the Commission first must present factual evidence that current cost allocation methods are unjust and unreasonable, or otherwise unduly discriminatory, which it has not done.

[530] *E.g.*, AWEA; ITC Companies; Multiparty Commenters; NextEra; and WIRES.

[531] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Arizona Corporation Commission; Arizona Public Service Company; City of Los Angeles Department of Water and Power; Santa Clara; E.ON; Large Public Power Council; Nebraska Public Power District; Northern Tier Transmission Group; Salt River Project; Transmission Agency of Northern California; Tucson Electric; Washington Utilities and Transportation Commission; WestConnect; and Westar.

Ad Hoc Coalition of Southeastern Utilities and Arizona Corporation Commission argue that participant funding most closely follows ''but for'' cost causation principles, and Ad Hoc Coalition of Southeastern Utilities adds that it is most consistent with judicial precedent regarding what constitutes an appropriate cost allocation method. Similarly, many commenters contend that the participant funding approach has led to the building of transmission projects that meet the reliability and economic needs of customers, and state and local policy goals.[532] Ad Hoc Coalition of Southeastern Utilities emphasizes that a requestor pays approach has been the norm for intersystem transmission projects in both the electric and gas industries. Arizona Corporation Commission, Salt River Project, City of Los Angeles Department of Water and Power, and Tucson Electric state that, in the West and Southwest, the participant-funded method of cost allocation has not delayed construction of transmission facilities and has been effective. Northern Tier Transmission Group believes that facilitating willing parties to make rational business decisions has a higher probability of causing the construction of new transmission than does a situation where costs could be forced upon unwilling parties, as is contemplated by the Proposed Rule.

719. In its reply comments, Entergy states that it believes that participant funding is an appropriate pricing method and should not be excluded from consideration in the Final Rule. Entergy requests clarification that any adverse finding against participant funding would not apply to customer-specific requests for service under the *pro forma* OATT. It notes that the Commission provided this clarification in Order No. 890, and it suggests that the Commission had the same intent in the Proposed Rule. Entergy argues that the types of projects set forth in the Proposed Rule do not include customer-specific requests for service, and it explains that such requests are evaluated pursuant to specific OATT procedures that govern system impact and facilities studies, and are performed in consultation with the affected customer, not vetted through a regional stakeholder process. Entergy notes that upgrades necessary to meet the specific request are similarly constructed to meet the needs of the customers, and are not subjected to a cost-benefit test to identify beneficiaries. Entergy cites to its own proposal regarding customer-specific service requests that the Commission found ''will promote, not discourage, efficient investments.'' [533]

720. Some commenters that support participant funding as a cost allocation method raise concerns about overly broad socialization of costs absent such a mechanism.[534] Large Public Power Council adds that the potential for cost socialization will lead to the planning process becoming vastly more contentious. Southern Companies argue that the proposed reforms are not consistent with cost causation principles. Likewise, Transmission Agency of Northern California argues that broad socialization of costs among all transmission customers is inconsistent with cost causation principles. Avista and Puget Sound state that the cost allocation proposals appear to improperly shift costs to existing customers that do not participate in projects. American Forest & Paper is concerned about the potential for overly broad socialization of costs to diminish incentives for cost-effective planning.

721. Some commenters believe that existing participant funding cost allocation processes are adequate and do not see a need at this time to change those existing processes.[535] These commenters and others,[536] primarily located in the Western Interconnection, believe that voluntary coordination and cost allocation of transmission facilities are more appropriate, particularly given their experiences, and that a mandatory cost allocation requirement could impede the transmission planning process and unintentionally delay or impede the development of new transmission.[537] California Commissions contend that this voluntary approach has minimized disputes and litigation. Arizona Public Service Company, Tucson Electric, and others suggest that voluntary participant funding of projects has permitted participants to successfully engage in allocating costs for transmission projects in the Southwest.

722. Commenters note other challenges to restricting participant funding. For example, California Commissions explain that assessment of benefits and beneficiaries is particularly challenging for long distance interregional transmission that would access remote renewable resources, given the uncertainties surrounding the ultimate build-out, cost (and cost competitiveness), and long-term purchasers for these resources, which are greatly complicated by the fact that energy and renewable energy credits may be purchased separately. Xcel states that MISO included a proposed solution to the ''first move/free rider'' issue, namely, that a generator interconnection customer who funds network upgrades pays the entire cost of those upgrades, regardless of other parties who may use them. Xcel asks that the Commission encourage such flexible and innovative solutions to such issues, particularly as public policy requirements are incorporated into transmission planning processes.

c. Commission Determination

723. The Commission finds that participant funding is permitted, but not as a regional or interregional cost allocation method. If proposed as a regional or interregional cost allocation method, participant funding will not comply with the regional or interregional cost allocation principles adopted above. The Commission is concerned that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. Because of this, it is likely that some transmission facilities identified as needed in the regional transmission planning process would not be constructed in a timely manner, adversely affecting ratepayers. On the other hand, we agree that if the costs of a transmission facility were to be allocated to non-beneficiaries of that transmission facility, then those non-beneficiaries are likely to oppose selection of the transmission facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the transmission facility's construction. For this reason, we adopt the cost allocation principles above that seek, among other things, to ensure that any regional cost allocation method or methods developed in compliance with this Final Rule allocates costs roughly commensurate with benefits.

[532] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Arizona Corporation Commission; City of Los Angeles Department of Water and Power; and Tucson Electric.

[533] *Entergy Servs., Inc.*, 115 FERC ¶ 61,095, at P 168 (2006).

[534] *E.g.*, Arizona Public Service Company; Large Public Power Council; Nebraska Public Power District; WestConnect; and Transmission Agency of Northern California.

[535] *E.g.*, WestConnect; PUC of Nevada; Transmission Agency of Northern California; and Coalition for Fair Transmission Policy.

[536] *E.g.*, Arizona Public Service Company; Bonneville Power; Tucson Electric; and California Transmission Planning Group.

[537] *E.g.*, Arizona Public Service Company; California Commissions; and Western Area Power Administration.

724. We therefore disagree with commenters who challenge this Final Rule's limitation on the use of participant funding on the grounds that it is inconsistent with the cost causation principle. Through the cost allocation principles adopted above, we require in all cases that regional and interregional cost allocation methods result in the allocation of costs for new transmission facilities in a manner that is roughly commensurate with the benefits received by those who will pay those costs. In proposing any cost allocation method or methods on compliance, there must be a demonstrated link between the costs imposed through a cost allocation method and the benefits received by beneficiaries that must pay those costs. However, these principles do not in any way foreclose the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility. Indeed, the evaluation of the potential benefits and beneficiaries of a proposed transmission facility may facilitate negotiations among such entities, potentially leading to greater use of participant funding for transmission projects not selected in the regional transmission plan for purposes of cost allocation.

725. Thus, we will not permit participant funding to be the cost allocation method for regional or interregional projects that are selected in a regional transmission plan for purposes of cost allocation. However, we are not finding that participant funding leads to improper results in all cases. For example, a transmission developer may propose a project to be selected in the regional transmission plan for purposes of regional cost allocation but fail to satisfy the transmission planning region's criteria for a transmission project selected in the regional transmission plan for purposes of cost allocation. Under such circumstances, the developer could either withdraw its transmission project or proceed to ''participant fund'' the transmission project on its own or jointly with others. In addition, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead, rely on participant funding.

726. Ad Hoc Coalition of Southeastern Utilities and Arizona Corporation Commission have not shown why participant funding is uniquely the cost allocation method that most closely follows ''but for'' cost causation principles. In fact, established precedent argues against this claim. Cost causation principles specify that, ''[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred [because] without the expectation of its contributions, the facilities might not have been built, or might have been delayed.'' [538] This statement embodies ''but for'' reasoning, and since participant funding does not in all cases capture all beneficiaries of new facilities, it cannot be said to be the cost allocation method that mostly follows ''but for'' cost causation principles.[539] Northern Tier Transmission Group argues that participant funding has a higher probability of causing the construction of new transmission facilities because it relies on willing parties and does not involve parties who are unwilling to bear costs and who will engage in litigation to oppose transmission project development. Yet nothing in this Final Rule precludes the use of participant funding for those transmission projects with the support of individual market participants. We find that Northern Tier Transmission Group's argument that other cost allocation methods will impair construction to be speculative and see no reason to conclude that other methods in fact will have this result.

727. In response to Transmission Agency of Northern California, Avista, and Puget Sound, we note that a limitation on participant funding is far from a mandate for broad cost socialization. There is nothing in our cost allocation reforms that requires broad socialization or supports improper cost shifting in violation of cost causation principles. As discussed fully above, our cost allocation principles require that costs be allocated roughly commensurate with the benefits received by those that pay those costs.

728. In any event, nothing in this Final Rule applies to existing transmission facilities with existing cost allocations or to transmission projects currently under development.[540]

729. In response to Entergy's request, we clarify that our cost allocation reforms in this Final Rule are not intended to modify existing *pro forma* OATT transmission service mechanisms for individual transmission service requests or requests for interconnection service.

[538] *Illinois Commerce Commission*, 576 F.3d 470 at 476.

[539] We discuss Ad Hoc Coalition of Southeastern Utilities' claim regarding the consistency of participant funding with judicial precedent on cost allocation methods below in section IV.F.2.

[540] *See also* discussion *supra* section III.A.3.

3. Whether Regional and Interregional Cost Allocation Methods May Differ

a. Commission Proposal

730. In the Proposed Rule, the Commission explained that the method used for allocating interregional transmission facility costs between any two transmission planning regions may be different from the method used by the public utility transmission providers located in either of those transmission planning regions to allocate the costs of new regional facilities. Additionally, the Commission proposed that the cost allocation method used by the public utility transmission providers located in a transmission planning region to allocate the costs of new regional facilities could be different from the cost allocation method by which the public utility transmission providers in the same transmission planning region further allocate costs to be borne by that transmission planning region pursuant to an agreed-upon method for allocating the costs of interregional facilities.[541]

b. Comments

731. Several commenters agree with the Commission's proposal that the method used for allocating interregional transmission facility costs may differ from the method used to allocate regional costs.[542] Georgia Transmission Corporation states that if an interregional coordination obligation would require entities to enter into agreements with neighboring regions, the Commission should specify that it would not require the transmission entity to accept the neighboring entity's cost allocation method. Indianapolis Power & Light states that the cost allocation provisions of an interregional coordination agreement should set forth how costs are divided between the regions and leave it up to the regions to determine how their shares are divided among their subregions/zones/customers. MISO Transmission Owners state that transmission providers and their stakeholders should be permitted to determine whether the cost allocation methods used for regional projects should apply to the transmission provider's share of interregional facilities.

732. ISO New England supports the preservation of a voluntary, flexible approach to interregional cost allocation that recognizes regional differences. It also states that the Final Rule should either clarify the manner in which

[541] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 176.

[542] *E.g.*, Georgia Transmission Corporation; Indianapolis Power & Light; MISO Transmission Owners; NEPOOL; and Northeast Utilities.

agreement on a cost allocation would be signified by each of the two regions or provide for flexibility in recognition of the mechanisms that may be most appropriate in light of the internal transmission planning processes of the paired regions.

c. Commission Determination

733. We find that the method or methods for interregional cost allocation used by two transmission planning regions may be different from the method or methods used by either of them for regional cost allocation. Also, the method or methods for allocating a region's share of the cost of an interregional transmission facility may differ from the method or methods for allocating the cost of a regional facility within that region.

734. Although the public utility transmission providers in a transmission planning region may choose to allocate their share of the costs of an interregional transmission facility using their regional cost allocation method or methods, we see no reason to require them to do so. Indeed, for a transmission planning region that shares the cost of regional transmission facilities broadly, it may be inappropriate to apply broad cost sharing for an interregional transmission facility that is found to benefit only part of that transmission planning region. In addition, an interregional transmission facility may be of such greater scale than most regional transmission facilities that it may result in different types of benefits and beneficiaries than for a regional transmission facility.

735. In response to Georgia Transmission Corporation, we clarify that we do not require the public utility transmission providers in a transmission planning region to accept the regional transmission planning method or methods of another transmission planning region with which it participates regarding interregional transmission coordination. Each transmission planning region would determine for itself how to allocate the costs of a new interregional transmission facility consistent with this Final Rule.

4. Recommendations for Additional Commission Guidance on the Application of the Transmission Cost Allocation Principles

736. Several comments recommend that the Commission provide additional guidance on how to apply the cost allocation principles.

a. Comments

737. A number of commenters provide additional suggestions on cost allocation methods. Duke states that without clear pricing guidelines that do more than restate general cost allocation principles, regional and interregional transmission projects will have trouble getting out of the starting gate. Pennsylvania PUC asserts that cost allocation principles and methods should be reasonably clear and explainable to all stakeholders so that development of a cost allocation paradigm can be effectively grasped by all participants. East Texas Cooperatives believe that the costs of all transmission facilities needed to maintain reliability or to deliver long-term resources to load serving entities should be rolled into the applicable zonal, regional, or interregional rate, and that individual cost allocation methods should clearly set forth a plan for identifying beneficiaries and allocating costs to them. Washington Utilities and Transportation Commission is concerned that necessary certainty on cost allocation would not be achieved if the Final Rule lacks detail on the standards to be applied when reviewing or approving cost allocations proposals and the Commission opts to develop more precise cost allocation policies on a case-by-case basis.

738. Federal Trade Commission encourages the Commission to consider providing stronger guidance regarding transmission cost allocation principles. It expresses its concern that unnecessary variance in allocation methods will have a disruptive effect on multi-area transmission proposals, akin to the disruptive effects that unnecessary diversity in methods for calculating available transmission capacity had on transmission services spanning multiple areas. Federal Trade Commission encourages the Commission to consider whether stronger guidance would promote consensus sooner and avoid creating a patchwork of transmission cost allocation methods that may not support broad, efficient regional markets and low-cost compliance with environmental and energy security policy initiatives.

739. WIRES states that, as proposed, the principles provide only the most general outer bounds of acceptable practice and do not specify the characteristics of cost allocation methods that the Commission is likely to consider just and reasonable. WIRES states that the use of a relatively complete set of principles affords the Commission an opportunity to help short-cut the endless debates about limited merits of participant funding in a network environment and about the extent to which the benefits of transmission can be quantified in specific instances.

740. Northwestern Corporation (Montana) asserts that new transmission lines should not be insulated from sharing a portion of the network costs and/or an allocation of the network revenue requirement because new transmission lines experience enhanced reliability by connecting to the network transmission system.

741. Illinois Commerce Commission urges the Commission to remove ''postage stamp'' cost allocation from the list of acceptable cost allocation methods.[543] It maintains that postage stamp cost allocation is highly unlikely to produce just, reasonable, and nondiscriminatory rates, and continuing to maintain it as a possible cost allocation method is paralyzing transmission expansion.

742. Other commenters make suggestions or requests for guidance that are similar to other commenters' recommendations for additional cost allocation principles discussed above. For example, some commenters suggest that cost allocation methods should be periodically recalculated or reevaluated. Many commenters believe that changes to transmission system topology and amendments to state policies could alter disbursement of benefits, so the Final Rule should require cost allocations to be periodically reviewed and recalculated.[544] Some of these commenters believe that permanent cost allocations may inhibit investing in transmission upgrades and that there should be periodic reassessments to address any unintended consequences.[545] For example, E.ON and East Texas Cooperatives suggest that cost allocation reevaluation should occur every five years. Pennsylvania PUC states that a cost allocation method should be designed to evolve and reflect system changes over time.

743. Ohio Consumers Counsel and West Virginia Consumer Advocate Division suggest that the Commission adopt a process that allows for expedited resolution of disputes over cost allocation that may arise during the regional planning process. ISO New

[543] ''Postage stamp'' here refers to regionwide allocation of the cost of a transmission facility.

[544] *E.g.,* Sunflower and Mid-Kansas; Electricity Consumers Resource Council and Associated Industrial Groups; PUC of Ohio; East Texas Cooperatives; E.ON; and Transmission Dependent Utility Systems.

[545] *E.g.,* Transmission Dependent Utility Systems; Sunflower and Mid-Kansas; E.ON; East Texas Cooperatives; and Massachusetts Municipal and New Hampshire Electric.

England recommends Commission-sponsored mediation or other alternative dispute resolution for interregional cost allocation to assist two regions on reaching agreement if they cannot do so.

744. Commenters also submitted comments suggesting multiple ways to allocate costs of public policy driven projects.[546] FirstEnergy Service Company believes the Commission should clarify that the cost causation principle, including the requirement that costs are at least roughly commensurate with benefits, applies with full force to public policy driven projects in the regional planning process. First Wind believes the Commission should seek state input and rely upon state judgment on cost allocation for projects flowing from state policy. NEPOOL and New England States Committee on Electricity believe that each region should have considerable flexibility to develop public policy cost allocations. Transmission Dependent Utility Systems notes that not all projects proposed to implement public policy are worthy of presumptive acceptance and should be rigorously scrutinized in the stakeholder process.

b. Commission Determination

745. The Commission appreciates interested commenters' views, suggestions and requests for additional Commission guidance regarding the development of an acceptable cost allocation method or methods to comply with the identified cost allocation principles for new regional and interregional transmission facilities. We believe, however, that the principles adopted in this Final Rule provide sufficient general guidance for public utility transmission providers. The principles establish threshold criteria for a cost allocation method or methods to facilitate the development of a just and reasonable and not unduly discriminatory or preferential cost allocation method or methods. Additionally, the principles afford public utility transmission providers in individual transmission planning regions the flexibility necessary to accommodate unique regional characteristics. The Commission is concerned that providing the additional guidance or limitations requested by commenters would unduly restrict this flexibility. As we explained above, the Commission recognizes the need for regions to retain some level of flexibility to account for specific regional characteristics, resource types, or policy mandates.

746. We emphasize, however, that any variations between regions must be consistent with the six cost allocation principles. For example, East Texas Cooperatives suggest periodic reevaluation of cost allocation methods to respond to system changes. We do not view such a proposal as inconsistent with the cost allocation principles adopted above and, as such, it could be presented and evaluated at the regional level and, if agreed upon, proposed to be implemented by that transmission planning region. However, the Commission declines to prescribe such a policy for all transmission planning regions nationwide.

747. With respect to comments regarding how to allocate costs for public policy driven transmission projects, as discussed above,[547] we are not requiring public utility transmission providers to use the same cost allocation method for public policy and other types of transmission facilities. Instead, as discussed for Cost Allocation Principle 6, we permit different regional and interregional cost allocation methods for different types of transmission projects. Thus, whether each region or pair of transmission planning regions has a separate cost allocation method for public policy driven transmission projects depends on the consensus within that transmission planning region or those transmission planning regions, and we will not prescribe a uniform method for such transmission projects.

748. In response to Illinois Commerce Commission, the Commission declines to find in advance that a ''postage stamp'' cost allocation may not be an acceptable cost allocation method. If public utility transmission providers in a region, in consultation with their stakeholders, agree to such a method, and it is demonstrated to be consistent with the cost allocation principles and is supported with an appropriate assessment of benefits, then such an allocation may be submitted to the Commission on compliance, and the Commission will determine then whether the method meets its requirements.

749. We also clarify that, by establishing the six principles for regional and interregional cost allocation, the Commission is not attempting to supersede the cost causation principle. Rather, these six principles serve as guidelines for public utility transmission providers to use to create cost allocation methods that are consistent with the cost causation principle.

750. With regard to the concerns of Ohio Consumers' Counsel, West Virginia Consumer Advocate Division, and ISO New England about dispute resolution, the Commission believes that the dispute resolution processes in place under Order No. 890, enhanced as may be necessary to comply with our transmission planning reforms, will be adequate to address in the first instance, any disagreements that may arise regarding the allocation of transmission costs. The Commission reviewed and approved all of the dispute resolution procedures currently in place during our review of the compliance filings in response to Order No. 890, requiring enhancements in a number of cases.[548] We will review any changes to those dispute resolution procedures in response to compliance filings submitted in response to this Final Rule.

G. Cost Allocation Matters Related to Other Commission Rules, Joint Ownership, and Non-Transmission Alternatives

751. Commenters also raised cost allocation issues related to generator interconnection costs in Order No. 2003,[549] pancaked transmission rates policy in Order No. 2000,[550] transmission rate incentives in Order No. 679,[551] the relationship of this proceeding to the proceeding on variable energy resources, Docket No. RM10–11–000, and joint transmission ownership.

[546] *E.g.,* FirstEnergy Service Company; First Wind; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; Public Power Council; and Transmission Dependent Utility Systems.

[547] *See* discussion *supra* section III.E.7.

[548] *See, e.g., Idaho Power Co.,* 128 FERC ¶ 61,064 at P 30–40; *Duke Energy Carolinas, LLC,* 127 FERC ¶ 61,281, at P 38–41 (2009); *New York Indep. Sys. Operator, Inc.,* 125 FERC ¶ 61,068, at P 61–64 (2008).

[549] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 68 FR 49846 (Aug. 18, 2003), FERC Stats. & Regs. ¶ 31,146, at P 676 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37661 (Jun. 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (DC Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[550] *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (DC Cir. 2001).

[551] Order No. 679, 71 FR 43294, FERC Stats. & Regs. ¶ 31,222, *order on reh'g,* Order No. 679–A, 72 FR 1152, FERC Stats. & Regs. ¶ 31,236, *order on reh'g,* 119 FERC ¶ 61,062.

1. Whether To Reform Cost Allocation for Generator Interconnections

752. In the Proposed Rule, the Commission did not propose to alter the cost recovery provisions of its generator interconnection rules.

a. Comments

753. Several commenters address the interaction between Order No. 2003 and the cost allocation requirements of this Final Rule. For example, Duke seeks clarification that impacts on transmission owners in neighboring regions resulting from a specific generator interconnection or transmission service request will continue to be addressed under the existing generation or transmission interconnection arrangements. East Texas Cooperatives urge the Commission to require development of an integrated process for studying network and point-to-point transmission service requests and generator interconnection requests that affect neighboring regions.

754. Other commenters address the interaction between Order No. 2003 and the transmission planning requirements. For instance, Solar Energy Industries and Large-scale Solar state that the Commission should require transmission providers to coordinate the transmission planning study process with the generator interconnection study process. PPL Companies agree stating that this would ensure that interconnection customers and native load bear their fair share of the costs of new transmission. On the other hand, NextEra believes that the costs of transmission projects identified through the transmission planning process should not be allocated to generators.

755. Some commenters urge the Commission to reevaluate the cost responsibilities in Order No. 2003 because they believe these are being used to circumvent the transmission planning process, creating a situation where load serving entities are forced to finance projects without project beneficiaries being identified.[552] If this continues, Bay Area Municipal Transmission Group asserts that greater transparency in the interconnection process is needed to facilitate the determination of the most cost-effective interconnection alternative. California Municipal Utilities argue that, if the costs of network upgrades identified through generator interconnection studies are borne by load within a region, those upgrades should be examined by the regional transmission planning process as a necessary precondition to approval by the relevant transmission provider. Six Cities note that the California ISO had represented in an Order No. 890 compliance filing that all interconnection-related network upgrades would be submitted through the request window open in each planning cycle and evaluated in the transmission planning process. Northern California Power Agency asserts that the generator interconnection process includes a loophole whereby transmission providers can circumvent the transmission planning process by proposing individual projects that are constructed by transmission providers, and recommends that the Commission limit the use of interconnection-related upgrades by ensuring they are a cost-effective means of grid expansion.

756. Several commenters discuss cost allocation for generation interconnection in the context of public policy projects. For example, Imperial Irrigation District asks the Commission to clarify that generation interconnection customers and their off-takers can be allocated the costs of public policy projects under the principles developed by transmission providers in each region when those generation project developers and their off-takers cause the need for or benefit from the public policy projects. In its reply comments, City of Santa Clara agrees with Imperial Irrigation District. Old Dominion agrees with PJM that greater clarity is needed regarding the extent to which the Commission is proposing that cost allocation for public policy driven projects depart from the existing Order No. 2003 framework. Old Dominion recommends that the Commission require all transmission providers to describe in their respective transmission planning and cost allocation tariff filings specific rules governing cost allocation for such projects.

757. East Texas Cooperatives state that they support a cost allocation policy under which the costs of network upgrades required to serve the native load of a transmission provider's network customers are rolled into the transmission provider's rates. They recommend that if a network upgrade is needed to accommodate an interconnection request for a generating facility that has not been designated as a network resource or is not otherwise contractually committed to serve customers within the transmission provider's footprint on a long-term basis, the interconnecting customer should be required to pay for the cost of network upgrades that would not have been required but for the interconnection request. They state that applying this policy would provide a level of assurance that the cost of such facilities will be allocated roughly commensurate to the estimated benefits.

758. Northern Tier Transmission Group asserts that, if a transmission provider does not execute an interconnection agreement with a generator, then the transmission provider has no mechanism to assess costs upon the generator. Northern Tier Transmission Group states that, to the extent the Commission chooses to address this practical issue, it should be done in the context of the generator interconnection procedures and agreements and not in the context of transmission planning.

759. In response, California ISO argues that such suggestions are beyond the scope of this proceeding and, if the Commission wishes to overhaul Order No. 2003, it should do so in a separate rulemaking so that parties have adequate notice that the Commission is proposing to modify its *pro forma* large generator interconnection procedures. Replying to Six Cities, California ISO argues that their assertion is based on a misconception that interconnection-related network upgrades need to be approved through the transmission planning process. California ISO states that Order No. 890 did not apply to such network upgrades.

b. Commission Determination

760. The Commission agrees with the California ISO and other commenters that issues related to the generator interconnection process and to interconnection cost recovery are outside the scope of this rulemaking. Order No. 2003 sets forth the procedures for the interconnection of a large generating transmission facility to the bulk power system. This Final Rule does not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities. Therefore, this Final Rule is not the proper proceeding for commenters to raise issues about the interconnection agreements and procedures under Order

[552] *E.g.,* Bay Area Municipal Transmission Group; California Municipal Utilities; and City of Santa Clara.

Nos. 2003,[553] 2006[554] or 661.[555] However, in not addressing these issues here, we are not minimizing the importance of evaluating the impact of generation interconnection requests during transmission planning, nor limiting the ability of public utility transmission providers to use requests for generator interconnections in developing assumptions to be used in the transmission planning process.

2. Pancaked Rates

a. Comments

761. A few commenters ask the Commission to address the pancaking of rates within transmission planning regions. Transmission Dependent Utility Systems assert that the Proposed Rule should eliminate regional rate pancaking as it remains a significant financial dilemma for many transmission customers and is destructive to regional planning. Transmission Dependent Utility Systems submit that if the Commission is going to implement a requirement for regional cost allocation, it should, at a minimum, eliminate pancaked rates unless there is an existing regional cost allocation method in place.

762. Sunflower and Mid-Kansas, on the other hand, contend that the Commission should modify its ''no pancaking'' policies for an RTO or ISO because the policy is not appropriate for large interregional projects and will potentially create extremely high rate increases for customers.

763. Gaelectric North America explains that merchant transmission developers are creating new pancaked rates. It asserts that, as public utilities construct radial merchant lines and allocate their costs through participant funding, they are creating additional pancaked rates for new generation owners who may wish to utilize these new facilities. Gaelectric North America argues that such pancaked rates inhibit the development and use of renewable resources. Further, it states that stringing radial transmission over network facilities is inefficient and pursued only to avoid appropriate cost allocation.

b. Commission Determination

764. We decline to make new findings with respect to pancaked rates in this Final Rule as it is beyond the scope of this proceeding. In particular, we do not make any modifications to the Commission's pancaked rate provisions for an RTO under Order No. 2000. If rate pancaking is an issue in a particular transmission planning region, stakeholders may raise their concerns in the consultations leading to the compliance proceedings for this Final Rule or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.

3. Transmission Rate Incentives

765. In the Proposed Rule, the Commission did not propose to alter its transmission rate incentive policies of Order No. 679.

a. Comments

766. Some commenters suggest that the Commission revisit its policy on transmission rate incentives, as set forth in Order No. 679. For example, they relate the Commission's proposals regarding nonincumbent transmission developers to transmission rate incentives.[556] Transmission Access Policy Study Group suggests that the Commission could require an incumbent transmission provider that exercises a federal right of first refusal to own and build a transmission facility to forgo any incentives on that facility. It argues that an incumbent transmission owner that exercises a federal right of first refusal should not then be given an incentive as necessary to encourage it to construct needed transmission. Minnesota Public Utilities Commission and Minnesota Office of Energy Security believe that one reason a federal right of first refusal may be justified is because there are instances where an incumbent transmission provider's rate of return is significantly lower than the incentive rate of return the Commission has approved for nonincumbent transmission developers. ITC Companies replies that such instances only demonstrate that different transmission incentives have been awarded in different cases by different regulatory bodies, noting that there are a variety of approved utility ROEs across the industry.

767. Other commenters tie the Commission's cost allocation proposals to transmission rate incentives. For example, APPA states that there is a clear causal connection between thorny cost allocation concerns and the Commission's incentive policy. APPA argues that when excessive transmission rate incentives are awarded to project sponsors, no one benefits from the associated costs except for the sponsors. Transmission Access Policy Study Group also suggests that the Commission use this opportunity to reevaluate application of Order No. 679 so that it does not add burdens on the economy or make siting and cost allocation issues more difficult than they already are. Transmission Dependent Utility Systems also state that transmission providers should be able to recover only the costs associated with a major transmission project through formula rates if that project was a product of an Order No. 890-compliant planning process that also meets the requirements of the Final Rule.

768. Joint Commenters recite cases in which project developers have been granted rate incentives that they believe substantially exceed the incentives that would result in just and reasonable rates. Joint Commenters also assert that the Commission has failed to recognize that the financial ground has shifted, citing the recent recession, historically low interest rates, and high unemployment. According to Joint Commenters, the rate of return needed to attract investment in a long-lived asset used to provide monopoly service is less than it was a few years ago. Finally, Joint Commenters recommend that the Commission revisit two features of its 1992 incentive rate policy statement,[557] concerning the requirement that incentive rate mechanisms be symmetrical and the requirement that applicants quantify the benefits to ratepayers as the incentive payment is awarded, arguing that these principles are equally important today. In its reply comments, Illinois Commerce Commission generally agrees with Joint Commenters, as does Organization of MISO States.

769. Pacific Gas & Electric recommends that the Commission clearly signal in the Final Rule that rate incentives are available for utilities that dedicate resources to the successful development of needed regional projects. In particular, Pacific Gas & Electric suggests that incentives for partnership in the development of major backbone projects crossing multiple

[553] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g,* Order No. 2003–A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g,* Order No. 2003–C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190, *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (DC Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[554] Order No. 2006, 70 FR 34189, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, 70 FR 71760, FERC Stats. & Regs. ¶ 31,196, *order granting clarification,* Order No. 2006–B, 71 FR 42587, FERC Stats. & Regs. ¶ 31,221.

[555] Order No. 661, 70 FR 34993 (Jun. 16, 2005), FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198.

[556] *E.g.,* New England States Committee on Electricity; Transmission Access Policy Study Group; and Southern California Edison.

[557] *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities,* 61 FERC ¶ 61,168 (1992).

jurisdictions are appropriate. Pacific Gas & Electric suggests that incentives should be offered for partnerships to both independent transmission companies and incumbent utilities, and that the incentives should be conditioned upon establishment of development arrangements that ensure consistent design standards are used that are compatible with the incumbent system, ongoing coordination of maintenance arrangements by responsible entities, and proper bilateral interconnection or coordinated operation agreements that will ensure the continuity and sustained reliability of the system.

770. However, a number of commenters oppose calls to reopen Order No. 679 in this proceeding.[558] Several commenters argue that such comments are beyond the scope of this rulemaking. They note that Order No. 679 was implemented in response to the direction of Congress, codified in section 219 of the FPA, to incent transmission investment. Some commenters note that Order No. 679 does not undermine transmission planning and cost allocation processes because the grant of incentives is conditioned on approval of the project under the relevant regional transmission planning processes. APPA states that it opposes blanket statements supporting the applicability of incentives under Order No. 679, and notes that Pacific Gas & Electric's request is illuminating because it shows how accustomed investor-owned utilities have become to obtaining such incentives and how they assume the Commission will simply rubber stamp in advance their requests for more incentives.

b. Commission Determination

771. We acknowledge commenters concerns regarding the Commission's policy on transmission rate incentives under Order No. 679. However, we decline to revisit or modify our policy under Order No. 679 in this Final Rule, as it is beyond the scope of this proceeding.[559]

4. Relationship of This Proceeding to the Proceeding on Variable Energy Resources

a. Comments

772. APPA argues that, contrary to the Commission's decision not to address transmission planning and cost allocation issues in its proceeding on the integration of variable energy resources (VER), Docket No. RM10–11–000, it believes that the two issues are not easy to compartmentalize. According to APPA, effective integration of VERs into regional transmission systems depends in large part on the availability of transmission facilities to support such integration, which in turn raises the issue of who will pay for the additional transmission facilities needed to undertake this integration effort. Thus, APPA urges the Commission to consider the tariff modification issues raised by VERs integration together with the need to develop cost allocation methods to pay for the additional transmission facilities that such integration requires.[560]

773. In its reply comments, Exelon argues that the Commission should address in this proceeding the operational issues entailed in integrating large amounts of VERs onto the grid in tandem with its rules for transmission planning and cost allocation. It states that whether or not the Commission issues a single rule in these dockets, it should rely on the record developed in the VERs rulemaking proceeding in deciding the Final Rule here, arguing that the record in the VERs proceeding fully supports the Commission requiring full accounting for the costs of integrating wind and other variable resources.

b. Commission Determination

774. This Final Rule establishes minimum requirements to guide the affected entities in developing their own transmission planning processes and cost allocation methods, which then will be submitted for filing with the Commission. The requirements established by this Final Rule apply to transmission planning and cost allocation for all resources. The VERs proceeding, however, addresses operational issues. To the extent that entities consider it necessary or appropriate to consider such operational issues in this Final Rule, they may do so by making a separate section 205 filing rather than raise issues on compliance in this proceeding.

5. Joint Ownership

a. Comments

775. A number of commenters urge the Commission to consider joint transmission ownership as a financing and cost allocation tool within the Proposed Rule. APPA and Six Cities ask the Commission to promulgate a rule favoring joint transmission ownership and to require that eligibility for rate incentives depend on an applicant's showing that it has offered reasonable opportunities for joint transmission ownership. APPA asserts that joint ownership diversifies financial risks and reduces the overall costs of the project as well as the need for transmission incentives. Transmission Access Policy Study Group and Transmission Agency of Northern California state that joint ownership leads to a more collaborative process in planning and development for both pooled systems and load serving entities. Transmission Access Policy Study Group states that joint ownership results in more diverse generation scenarios, shorter permitting processes during siting, and simpler resolutions of cost allocation issues, and points out that joint ownership spreads the risk of projects and provides a variety of sources of capital for projects.

b. Commission Determination

776. Specific financing techniques such as joint ownership are beyond the scope of this proceeding. Transmission developers are, of course, free to consider joint ownership when proposing and developing a transmission project. Just as we are not requiring any specific cost allocation method, we do not specifically address joint ownership as a cost allocation tool in this proceeding. However, we reiterate here our statement in Order No. 890 that we believe there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers.[561]

6. Cost Recovery for Non-Transmission Alternatives

a. Comment Summary

777. GridSolar suggests that the Commission require utilities and RTOs/ISOs to evaluate alternatives to traditional transmission solutions on the same basis, using the same standards as those used for traditional transmission solutions, and that this could be done through a competitive solicitation. GridSolar notes that distributed energy resources connect at voltages below 69 kV and therefore do not qualify for cost allocation treatment under the

[558] *E.g.,* AEP; Edison Electric Institute; EIF Management; ITC Companies; National Grid; Pacific Gas & Electric; and PSEG Companies.

[559] The Commission issued a Notice of Inquiry on May 19, 2011 regarding its policy on transmission incentives under Order No. 679. *See Promoting Transmission Investment Through Pricing Reform,* Notice of Inquiry, 135 FERC ¶ 61,146 (2011).

[560] APPA also incorporates by reference the comments it submitted in Docket No. RM10–11–000.

[561] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 593.

transmission planning process although they provide the same services as other transmission resources. Similarly, 26 Public Interest Organizations argue that transmission and non-transmission solutions should be treated comparably for cost recovery purposes.

778. FirstEnergy Service Company argues that while the Proposed Rule does not address cost recovery for non-transmission projects, only the costs of facilities that perform a transmission function (including energy storage projects) should be included in transmission rates. FirstEnergy Service Company argues that regional transmission planning processes should not be a vehicle for owners of generation or demand side management projects that are eligible to earn revenue from sales of energy, capacity, and ancillary services to earn subsidies from transmission customers.

b. Commission Determination

779. As we make clear above in the section on Regional Transmission Planning, we are maintaining the approach taken in Order No. 890 and will require that generation, demand resources, and transmission be treated comparably in the regional transmission planning process.[562] However, while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, we conclude that the issue of cost recovery for non-transmission alternatives is beyond the scope of the transmission cost allocation reforms we are adopting here, which are limited to allocating the costs of new transmission facilities.[563]

V. Compliance and Reciprocity Requirements

A. Compliance

1. Commission Proposal

780. With the exception of the proposed interregional transmission coordination and interregional cost allocation requirements, the Proposed Rule would require each public utility transmission provider to submit a compliance filing within six months of the effective date of the Final Rule in this proceeding. With regard to the proposed interregional transmission coordination and interregional cost allocation requirements, the Proposed Rule would require each public utility transmission provider to submit a compliance filing within one year of the effective date of the Final Rule in this proceeding.[564] The Commission proposed that it would assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of the Proposed Rule.

2. Comments

781. Exelon urges the Commission to adhere to its original time schedule for compliance filings of six months for intraregional transmission planning and one year for interregional agreements. In its reply comments, LS Power argues that the six-month and twelve-month compliance deadlines are far more generous than the 60-day deadline that the Commission provided for compliance with Order No. 888 and the filing of revised power pooling and multilateral coordination agreements, respectively.

782. Some commenters suggest that the Commission extend the compliance deadlines for up to three years.[565] Indianapolis Power & Light and SPP state that the proposed six-month and one-year deadlines do not allow sufficient time for the stakeholder process. Indianapolis Power & Light states that this is particularly true if the right of first refusal is removed and recommends that the Commission extend the deadlines by a minimum of one year. SPP recommends that the Commission extend the proposed deadline for regional transmission planning by at least six months and for interregional transmission planning and cost allocation to three years. MISO Transmission Owners state that the Commission should extend all compliance deadlines by a minimum of six months. Arizona Corporation Commission states that the Commission should recognize that most public utility transmission providers in the West are not members of an RTO and will need more time, perhaps 24–36 months, to draft regional and interregional transmission plans. Arizona Public Service Company agrees in is reply comments that the compliance deadlines are too aggressive, arguing that the Commission is proposing a vast array of changes that will require utilities to develop positions, collaborate with neighboring utilities, and reach consensus with regional groups.

783. Western Area Power Administration recommends that, in lieu of compliance filings, the Commission require transmission providers to file periodic status reports regarding intraregional and interregional efforts. As an alternative approach, it recommends that the Commission extend the compliance filing deadline to one year for intraregional transmission planning and cost allocation issues and two years for interregional issues. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council recommend that in lieu of the proposed one-year compliance filing requirement, that the Commission call for status updates on these matters in one year's time, potentially to be followed by further orders on a regional basis establishing reasonable timeline targets.

784. Focusing on the six month regional planning compliance deadline, some commenters express the view that six months is a reasonable compliance period.[566] LS Power notes that many of the commenters expressing opposition to the six-month compliance deadline are the same entities that are opposed to removal of the federal right of first refusal, suggesting that any extension of compliance periods not apply to the federal right of first refusal from jurisdictional OATTs and agreements.

785. Other commenters express concern about the ability of transmission providers to meet the six-month compliance filing requirement for regional transmission planning requirements.[567] New England States Committee on Electricity states that a Final Rule addressing the rights and obligations of nonincumbent transmission providers within the regional planning process should provide the planning regions adequate time to sort through a means of complying. Xcel urges the Commission to allow entities in the Western Interconnection sufficient time and latitude to develop mechanisms that effectively meet the needs of the region; it states that, given the needs of the western region, six months or even one year is an unreasonably short period of time to build a structure to comply with the Commission's regional transmission planning requirements. Washington Utilities and Transportation Commission states that the Commission need not proceed with urgency but

[562] *See* discussion *supra* Section III.A.

[563] As we stated in the Proposed Rule, the Commission has recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes. *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.58 (citing *Western Grid Development, LLC,* 130 FERC ¶ 61,056 (2010)).

[564] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 179.

[565] *E.g.,* Indianapolis Power & Light; SPP; MISO Transmission Owners; Arizona Corporation Commission; and Arizona Public Service Company.

[566] *E.g.,* Northwest & Intermountain Power Procedures Coalition and LS Power.

[567] *E.g.,* New England States Committee on Electricity and Xcel.

should allow existing regional processes to mature, which may lead to a more expeditious and effective transmission planning process.

786. Focusing on the one year interregional compliance deadline, East Texas Cooperatives state that, given the urgent need for interregional transmission planning reform, the Commission should require filing of interregional transmission planning agreements within six months of the effective date of the Final Rule. In its reply comments, East Texas Cooperatives add that shortening this deadline would motivate transmission providers to improve coordination with their adjacent regions. Exelon states that for sets of regions that currently have Commission-approved joint operating agreements, the Commission should require a six-month compliance filing.

787. Other commenters contend that the one-year time period for compliance filings relating to interregional transmission planning agreements is unworkable. Southern Companies doubt that an interregional cost allocation agreement could be developed in the Southeast within the proposed one-year deadline. ISO/RTO Council states that this proposal is unworkable due to the complexity, limited resources, the need to involve stakeholders, and potentially the number of agreements to be reached. NV Energy agrees, stating that significant additional time is needed to address interregional transmission agreements and cost allocation issues given the number of parties involved. Xcel agrees that the proposed one-year deadline is unattainable and the Commission should allow more time for interregional planning and cost allocation initiatives to develop voluntarily.

788. Duke and Georgia Transmission Corporation state that the Commission should provide two years to submit interregional transmission planning agreements, given the number of parties that may be involved and the difficulties of developing cost allocation methods. Edison Electric Institute requests that the Commission be flexible regarding compliance deadlines for interregional agreements and cost allocation and consider allowing up to two years for compliance. Pennsylvania PUC states that interregional agreements will require many actions internal to RTOs and ISOs and planning organizations, therefore the Commission should consider expanding the compliance period from one year to 18 or 24 months.

789. With regard to compliance filings by RTOs and ISOs, New York ISO argues that the Commission should narrow the scope of the compliance filings required under the Final Rule so that RTOs and ISOs are not effectively compelled to demonstrate compliance with requirements that they have already satisfied in their individual Order No. 890 planning proceedings. Several commenters also urge the Commission to consider existing RTO or ISO cost allocation methods as compliant with the proposed cost allocation principles and to avoid reopening debates about regional cost allocation methods already approved by the Commission.[568] Some of these commenters argue that existing processes, such as those used in California ISO and ISO New England, are reasonable [569] while others disagree.[570]

790. Several commenters state that the Commission should not lightly change existing regional cost allocation methods.[571] For example, Duke states that parties challenging the appropriateness of an existing Commission-approved method should bear a heavy burden of showing why that method is inconsistent with the Final Rule. Transmission Dependent Utility Systems state that the Commission should not automatically disrupt current regional cost allocation methods but instead require compliance filings that demonstrate that the regional cost allocation method was indeed the product of an open and inclusive stakeholder process and that the regional cost allocation method either meets the Commission's proposed cost allocation principles, or that the existing regional cost allocation method is consistent with or superior to the requirement of those principles.

791. Additionally, MISO Transmission Owners, Indianapolis Power & Light, and SPP recommend that the Commission clarify that transmission owners in an RTO or ISO are permitted to participate in the compliance filing of the RTO or ISO without making a separate compliance filing of their own. Omaha Public Power District suggests that providers that are not members of an RTO be allowed to participate in the relevant RTO planning process to achieve the interregional planning mandate because this would reduce the cost of coordination and improve its efficiency and effectiveness.

3. Commission Determination

792. Given the various comments requesting a longer compliance period, we extend the compliance filing requirements set forth in the Proposed Rule. Accordingly, we find that, with the exception of the requirements with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods, each public utility transmission provider must submit a compliance filing within twelve months of the effective date of this Final Rule revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth in this Final Rule.[572] The Commission also requires each public utility transmission provider to submit a compliance filing within eighteen months of the effective date of this Final Rule revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth herein with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods. As explained below, we expect that the twelve month and eighteen month deadlines provide sufficient time for each public utility transmission provider to meet the requirements of this Final Rule.

793. For those suggesting that current transmission planning and cost allocation initiatives should be allowed more time to develop, we find that the need to provide rates, terms and conditions of jurisdictional service that are just and reasonable and not unduly discriminatory or preferential, and the need to build new transmission facilities that more efficiently or cost-effectively support the reliable development and operation of wholesale electricity markets, requires that the reforms adopted in this Final Rule are implemented in a timely

[568] *E.g.,* California ISO; SoCal Edison; San Diego Gas & Electric; Eastern Mass. Consumer Owned System; Northeast Utilities; MISO; New York ISO; NEPOOL; New England States Committee on Electricity; Kansas Corporation Commission; and Xcel.

[569] *E.g.,* California PUC; Pacific Gas & Electric; NEPOOL; and Connecticut & Rhode Island Commissions.

[570] Several commenters, such as the Integrated Transmission Benefits Model Proponents and Maine Parties argue that ISO New England's current transmission planning and cost allocation methods do not comply with this Final Rule. These concerns should be raised during the stakeholder process used to develop compliance with this Final Rule. To the extent that a commenter believes that its concerns have not been resolved in the relevant compliance filing, it can raise those concerns at that time in a protest to the compliance filing.

[571] *E.g.,* Duke; New Jersey Board; Northeast Utilities; and Transmission Dependent Utility Systems.

[572] *See* Appendix C for the *pro forma* Attachment K consistent with this Final Rule.

fashion.[573] The Commission concludes that the time periods provided for adoption of these reforms—twelve months for regional transmission planning and cost allocation reforms and eighteen months for interregional reforms—are reasonable and achievable. These extended time periods provide additional time for public utility transmission providers to work with their stakeholders to develop transmission planning and cost allocation processes that conform with the requirements adopted herein.

794. We find that the compliance time periods established in this Final Rule strike an appropriate balance between implementing needed reforms to transmission planning and cost allocation processes in a timely fashion and providing time for those involved in these processes to work with stakeholders to develop transmission planning and cost allocation processes that conform with the requirements adopted herein. Moreover, we believe these compliance filing deadlines are compatible with the interests of those that intend to develop transmission planning processes that take into account the lessons learned through the ARRA-funded transmission planning initiatives, discussed above in section I.C and III.C.I, under which the participants of each interconnection are currently collaborating on transmission planning to produce an initial long-term plan in mid-2012 and a final plan in 2013. For this same reason, we are not persuaded by those commenters that recommend that the Commission require periodic status reports in lieu of compliance filings.

795. In response to commenters' requests, we clarify that an RTO or ISO and its public utility transmission provider members may make a compliance filing that demonstrates that some or all of its existing RTO and ISO transmission planning processes are already in compliance with this Final Rule, and we will consider this demonstration and any contrary views on compliance. We require every public utility transmission provider, including an RTO or ISO transmission provider, to file its existing or proposed OATT provisions with an explanation of how these provisions meet the requirements of this Final Rule. While many of the existing transmission planning and cost allocation processes and methods may be similar to what this Final Rule requires, others may differ because this Final Rule's requirements expand on the Order No. 890 requirements. Whether an existing process was approved previously by the Commission is not dispositive of whether that process complies with this Final Rule.

796. We recognize that it is possible that some existing RTO and ISO transmission planning and cost allocation processes may already satisfy the Commission's proposal in whole or in part. However, we decline to rule generically, in the absence of a record based on a comparison of existing practices with the provisions of this Final Rule, on the degree to which a particular RTO or ISO may already be in compliance.

797. Furthermore, public utility transmission owners that are part of Commission-jurisdictional RTOs and ISOs may demonstrate compliance through that RTO's or ISO's compliance filing and are not required to make a separate compliance filing. This includes, in response to SPP, compliance with the interregional transmission coordination requirements to the extent an RTO or ISO has negotiated the necessary arrangements on behalf of its members. In response to Omaha Public Power District, we encourage both RTO and ISO members and those not in an RTO or ISO to work together regarding regional transmission planning. We neither prohibit non-RTO/ISO members that are geographically adjacent to and/or contiguous with an RTO/ISO from participating in the RTO/ISO's regional transmission planning process nor do we require an RTO/ISO to admit nonmembers to its regional transmission planning process. The decision on whether to combine their transmission planning efforts in this way to comply with the regional transmission planning and regional cost allocation requirements and the interregional transmission coordination requirements and interregional cost allocation requirements of this Final Rule is a decision that is best left to the individual entities as well as to the two regions in question. In addition, the OATT for the RTO or the ISO of which a public utility transmission provider is a part should include commonly agreed-to language describing that RTO/ISO's interregional transmission coordination with each neighboring transmission planning region.

798. In addition, in non-RTO/ISO regions, if public utility transmission providers in those regions decide to make combined compliance filings, they are free to do so. However, each public utility transmission providers' OATT must include the reforms required in this Final Rule.

B. Reciprocity

1. Commission Proposal

799. The Commission proposed that transmission providers that are not public utilities (*i.e.,* non-public utility transmission providers) would have to adopt the requirements of the Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[574] The Commission also stated that if it finds on the appropriate record that a non-public utility transmission provider is not participating in the proposed regional transmission planning and cost allocation processes set forth in this Final Rule, the Commission may exercise its authority under FPA section 211A [575] on a case-by-case basis.[576]

2. Comments

800. Some commenters question whether non-jurisdictional entities can legally be required to participate in regional and interregional transmission planning and cost allocation processes. Several non-jurisdictional entities suggest that they cannot. For example, Bonneville Power asserts that the proposed mandatory cost allocation reforms could conflict with its statutory obligations. Bonneville Power states that

[573] This finding is supported by our discussion above in section II.

[574] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 181 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63). Under the *pro forma* OATT, a non-public utility transmission provider may satisfy the reciprocity condition in one of three ways. First, it may provide service under a tariff that has been approved by the Commission under the voluntary ''safe harbor'' provision of the *pro forma* OATT. A non-public utility transmission provider using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the *pro forma* OATT. The non-public utility transmission provider then must offer service under its reciprocity tariff to any public utility transmission provider whose transmission service the non-public utility transmission provider seeks to use. Second, the non-public utility transmission provider may provide service to a public utility transmission provider under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility transmission provider may seek a waiver of the reciprocity condition from the public utility transmission provider. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[575] FPA section 211A(b) provides, in pertinent part, that ''the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services—(1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' The non-public utility transmission providers referred to in this Final Rule include unregulated transmitting utilities that are subject to FPA section 211A.

[576] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 43.

it is required by statute to have Congressional approval before it can build facilities outside the Pacific Northwest or build major transmission facilities within the Pacific Northwest. Bonneville Power states that it is obligated to determine the appropriateness of its transmission expenditures, and those expenditures are subject to specific directives or limitations that Congress may include in its appropriation acts. As a result of these statutory obligations, Bonneville Power contends that it must retain the right to review each proposal and agree to any proposed allocation of costs from another party.

801. Western Area Power Administration states that it is a federal power marketing administration and must comply with statutory requirements that apply to such entities, such as the Anti-Deficiency Act, the Reclamation Project Act of 1939, and the Flood Control Act of 1944. Western Area Power Administration argues that these statutory requirements preclude involuntary cost allocation of third-party transmission facilities to it. Western Area Power Administration also argues that requiring it to incorporate a mandatory cost allocation share into its rates is inconsistent with the jurisdiction over, and power to review, Western Area Power Administration's rates that the Department of Energy delegated to the Commission.

802. Bonneville Power requests that the Commission explain the effect of reciprocity in the context of transmission planning and cost allocation. Bonneville Power states that if the Commission conditions reciprocity on adherence to the Proposed Rule, it requests that the Commission state in the Final Rule that it will accommodate deviations in compliance filings that are necessary to allow non-public utilities to participate. Bonneville Power contends that if the Commission does not accept regional deviations, coordinated regional planning and cost allocation will likely be unworkable for both public and non-public utilities in the Pacific Northwest.

803. Public Power Council asserts that the Commission's proposed cost allocation method will drive non-public utilities out of the voluntary planning process. Public Power Council states that governmentally-owned utilities are subject to state statutes that may limit their ability to enter into contracts involving unknown future costs and that bind future district commissions or city councils. Public Power Council thus argues that the Commission should either abandon its proposal to require binding cost allocation agreements for non-RTO areas or withdraw its proposal that voluntary participant funding cannot be the sole method of cost allocation when the transmission provider is not a participant in an RTO. Omaha Public Power District states that it is committed to voluntary participation in the transmission planning process. However, it also states that as a state political subdivision it is not subject to the Commission's general jurisdiction under the FPA and that the Commission has no authority to set rates for it without its consent.

804. Four G&T Cooperatives argues that the Commission does not have jurisdiction under the FPA to require non-public utilities to participate in regional transmission planning processes or to agree to regional cost allocation methods. It also argues that the reciprocity provisions under Order Nos. 888 and 890 and the *pro forma* OATT do not provide a basis for requiring non-public utilities to participate in regional transmission planning and cost allocation. National Rural Electric Coops state that the Commission has consistently refused to expand the reach of the reciprocity provision to include transmission customers other than those from which the non-public utility is taking service and those who are transmission-owning members of an RTO or ISO. G&T Cooperatives and National Rural Electric Coops request clarification that the Commission is not modifying the scope of the reciprocity requirement as established in Order Nos. 888, 890, and 890–A.

805. Western Grid Group, on the other hand, recommends that to engage non-jurisdictional utilities in regional planning groups, the Commission should make it clear that such participation is a requirement for Commission recognition of reciprocity tariffs and that all entities that share the grid have an obligation in the public interest to help plan its expansion and modernization.

806. SPP states that, consistent with the approach set forth in Order No. 890, the Commission should continue to encourage participation by non-jurisdictional entities in regional transmission planning processes. SPP also states that the Commission should consider requiring non-jurisdictional entities that have reciprocity tariffs on file with the Commission to modify those tariffs specifically to address the obligation to participate in the regional transmission planning process and cost allocation mechanism development. Similarly, San Diego Gas & Electric suggests that Order No. 888's reciprocity requirements be enforced, as necessary. Anbaric and PowerBridge also believe that the Final Rule should apply to all transmission providers, including to those subject to the Commission's reciprocity requirements.

807. A number of commenters also address the Commission's authority under FPA section 211A. National Rural Electric Coops argue that the Commission's jurisdiction under FPA section 211A is limited to requiring a subset of unregulated transmitting utilities to provide transmission services to others on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential. National Rural Electric Coops asserts that it is concerned that the Commission may be interpreting FPA section 211A to mean that it could invoke the provision in circumstances other than those in which it makes a finding that an unregulated transmitting utility is not treating its transmission customers in a way that is comparable to the way it treats itself. National Rural Electric Coops request that the Commission clarify that it will address questions of non-comparable treatment on a case-by-case basis as necessary. National Rural Electric Coops state that such a clarification could help avoid unnecessary litigation.

808. Imperial Irrigation District questions the Commission's legal authority to allocate costs to non-public utilities via either the reciprocity principle or FPA section 211A. It states that cost allocation is a rate issue, and Congress has not authorized the Commission to set rates for non-public utilities. It argues that under the Commission's reciprocity principle, the Commission does not set rates of non-public utilities.

809. Large Public Power Council and Nebraska Public Power District state that the proposed reciprocity requirement would dramatically expand the commitment that non-public utilities were asked to make under Order No. 888 and ensuing orders and would greatly exceed the Commission's authority. They state that FPA section 211A does not permit the Commission to compel a non-public utility to contribute funding for regional or interregional transmission projects, nor would it enable the Commission to exercise any authority over the transmission planning or construction plans of a non-public utility. Sacramento Municipal Utility District urges the Commission to reconsider its proposal to invoke FPA section 211A

authority on a case-by-case basis. It states that this is unnecessary, beyond the limited reciprocity requirements of Order Nos. 888 and 890, and it is beyond the Commission's authority. Western Area Power Administration states that FPA section 211A does not authorize the Commission to require unregulated transmitting utilities to engage in regional transmission planning and cost allocation.

810. Western Area Power Administration and National Rural Electric Coops request clarification that the Commission did not intend its statements in the Proposed Rule regarding FPA section 211A and the reciprocity provisions of Order Nos. 888 and 890 to expand its authority over non-public utilities. Georgia Transmission Cooperative argues that the Commission has not provided evidence to support application of FPA section 211A and that applying it would be inconsistent with prior Commission statements that non-public utilities are not subject to the same cost allocation rules as public utilities.

811. Transmission Access Policy Study Group and Colorado Independent Energy Association support the Commission's proposal to invoke reciprocity for non-jurisdictional transmission providers as needed to achieve its goals, and they agree with the Commission's decision not to invoke its authority under FPA section 211A. Colorado Independent Energy Association also recommends that to avoid the use of FPA section 211A, the Commission should provide a *pro forma* OATT and a date certain for non-jurisdictional entities to report their progress to the Commission regarding incorporation of the principles set forth in the Proposed Rule into their OATTs and practices. Transmission Agency of Northern California believes that the demonstrated willingness of non-public utility transmission providers to comply voluntarily with Commission directives shows that an explicit requirement that they comply with the Proposed Rule is unnecessary.

812. Other commenters, including MidAmerican and NextEra, suggest that the Commission should apply reciprocity or exercise its authority under FPA section 211A to require non-public utilities to participate in regional and interregional transmission planning and cost allocation processes. MidAmerican states that the Commission has the authority to require all non-jurisdictional utilities to comply with, and remain subject to, the proposed transmission planning and cost allocation requirements and that the Commission should use this authority if it intends to achieve its stated objectives on a non-discriminatory basis. MidAmerican believes that failure to include all transmission providers will result in an inequitable burden for jurisdictional utilities and their customers, and it will create additional investment uncertainty for projects included in the regional plan. NextEra supports the use of FPA section 211A to extend the requirements of the Final Rule to unregulated transmitting utilities. It believes that invoking FPA section 211A on a case-by-case basis is risky and may not ensure maximum participation by unregulated utilities. AWEA states that the Commission should make clear its intention to invoke FPA section 211A as necessary to ensure needed participation in regional transmission efforts and cost allocation requirements.

813. Bonneville Power asserts in its response that neither the Proposed Rule, nor any of the initial comments, provide evidence that supports invoking FPA section 211A, either on a case-by-case basis or generically. Bonneville Power disagrees with MidAmerican that public utility transmission providers would be subject to undue discrimination if non-public utilities do not participate in transmission planning and cost allocation. It argues that any differences in treatment would result from adopting the Proposed Rule, not from discrimination by non-public utilities. Large Public Power Council disagrees that the Commission has authority under FPA section 211A to compel non-public utilities to participate fully in whatever planning and cost allocation rules are adopted in this proceeding. It also states that the Commission cannot accomplish indirectly through its reciprocity provisions what it cannot accomplish directly under the statute.

814. MidAmerican also suggests that the Commission use its conditioning authority to require non-jurisdictional utilities to participate in the regional transmission planning and cost allocation processes, stating that the Commission has already taken this approach under FPA section 215. However, in reply, Large Public Power Council disagrees, noting that section 215 explicitly extends Commission jurisdiction for reliability purposes over a wide range of entities, thereby confirming that express direction from Congress is required before the Commission can exercise jurisdiction over otherwise non-jurisdictional entities.

3. Commission Determination

815. To maintain a safe harbor tariff, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT as it has been revised by this Final Rule. As noted in the Proposed Rule, we are encouraged, based on the efforts that followed Order No. 890, that both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA section 211A, which gives us authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis. However, if the Commission finds on the appropriate record that non-public utility transmission providers are not participating in the transmission planning and transmission cost allocation process required by this Final Rule, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

816. Given our decision above, we decline to adopt SPP's suggestion that the Commission require non-public utility transmission providers that have safe harbor tariffs on file to modify those tariffs specifically to address the transmission planning and cost allocation processes required by this Final Rule. Rather, it remains up to each non-public utility transmission provider whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.[577] We also note in response to National Rural Electric Coops and others that the Commission is not proposing any changes to the reciprocity provision of the *pro forma* OATT or any other document. The Commission is not modifying the scope of the reciprocity provision.

817. We disagree with Colorado Independent Energy Association that the Commission should impose any requirements on non-public utility transmission providers for the purpose of avoiding recourse to section 211A, as we do not see any necessity, at this time, to invoke our authority under that

[577] For this same reason, we find that it is not necessary to address Anbaric and PowerBridge's suggestion that this Final Rule should apply to all transmission providers, including those subject to the Commission's reciprocity provisions and enforced as necessary. However, we reiterate our determination in section IV.E.2. that an entity participating in the regional transmission planning process can be identified as the beneficiary of a regional transmission facility and allocated associated costs, irrespective of its status as a public utility under the FPA.

section. In addition, we disagree with MidAmerican, NextEra, and SPP that we should establish requirements regarding participation by non-public utility transmission providers in regional and interregional transmission planning and cost allocation processes beyond those required by reciprocity. We likewise disagree with Western Grid Group that we need to clarify for non-public utility transmission providers the importance of their participation in the processes established by this Final Rule.

818. The Commission recognizes that many of the existing regional transmission planning processes are comprised of both public and non-public utility transmission providers. In the Proposed Rule, the Commission described the significance of its proposal for non-public utility transmission providers in terms of the principle of reciprocity.[578] None of the commenters has provided a persuasive reason for departing from the position taken in the Proposed Rule. Thus, as noted above, and consistent with the approach taken in Order No. 890, the Commission expects all public utility and non-public utility transmission providers to participate in the transmission planning and cost allocation processes set forth in this Final Rule. The success of the reforms implemented here will be enhanced if all transmission owners participate. Further, we believe that non-public utility transmission providers will benefit greatly from the improved transmission planning and cost allocation processes required for public utility transmission providers because a well-planned grid is more reliable and provides more available, less congested paths for the transmission of electric power in interstate commerce. Those that take advantage of open access, including improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.

819. In response to G&T Cooperatives and others, we note that the Commission is not acting here under the FPA to require non-public utility transmission providers to participate in regional transmission planning processes or to agree to a method or methods for allocating the costs of their transmission facilities. Under the reciprocity provision, if a public utility transmission provider seeks transmission service from a non-public utility transmission provider to which it provides open access transmission service, the non-public utility transmission provider that owns, controls or operates transmission facilities must provide comparable transmission service that it is capable of providing on its own system.[579] A non-public utility transmission provider that elects to receive such service, therefore, must do so on terms that satisfy the reciprocity condition. We disagree that we are using the principle of reciprocity to expand our jurisdiction over non-public utility transmission providers. Non-public utility transmission providers are free to decide whether they will seek transmission service that is subject to the Commission's jurisdiction, and we do not exercise jurisdiction over them when we determine the terms under which public utility transmission providers must provide that transmission service.

820. While a number of commenters argue that this Final Rule's reforms could conflict with their statutory obligations, no specific conflict has been presented for us to act on in this Final Rule. Concerns about possible conflicts should be raised in transmission cost allocation discussions and any subsequent Commission proceedings on proposed transmission cost allocation methods.

821. We disagree with National Rural Electric Coops that our discussion of FPA section 211A in the Proposed Rule is unclear or ambiguous. However, in response to National Rural Electric Coops we note that our intent is to invoke section 211A only on a case-by-case basis. We see no reason to reconsider our position on section 211A as Sacramento Municipal Utility District requests, nor a need to address additional arguments concerning the scope of our authority under section 211A given that we are not acting under section 211A in issuing this Final Rule. Likewise, in response to Georgia Transmission Cooperative, we do not need to provide evidence in this proceeding to support the application of FPA section 211A because we are not applying it here.

822. With regard to Transmission Agency of Northern California's suggestion that an explicit requirement that non-public utility transmission providers comply with the Proposed Rule is unnecessary because they are already complying, we note that this Final Rule does not include any such explicit requirement and instead only notes an expectation that non-public utility transmission providers will participate voluntarily.

VI. Information Collection Statement

823. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[580] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

824. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[581] In the Proposed Rule, the Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission also included a chart that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements. The Commission received one comment from Arizona Public Service Company specifically addressing the Commission burden estimate in the Proposed Rule.

825. Arizona Public Service Company states that while it supports the need for a robust regional transmission planning process, it contends that the burden estimate in the Proposed Rule understated the number of hours and the average rates of the employees working on these processes. As an example, Arizona Public Service Company states that it participates in WestConnect, which in the past twelve months has involved over two dozen regional or subregional transmission planning meetings. According to Arizona Public Service Company, many of these meetings last an entire day, and require a significant amount of preparation work prior to the meeting. It further contends that the Commission should have included calculation of travel expenses of participants in the regional transmission planning

[578] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 43.

[579] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[580] 5 CFR 1320.11(b).

[581] 44 U.S.C. 3507(d).

processes, including transportation, lodging, and meal expenses.

826. In the Proposed Rule, the Commission estimated the number of hours required for the average public utility transmission provider to comply with the minimum requirements included in the Proposed Rule. The burden estimates in this Final Rule represent the incremental burden changes related only to the requirements set forth in this Final Rule.[582] It should also be noted that the burden estimates are averages for all of the filers. Furthermore, we acknowledge that some regional transmission planning processes have been developed to date that may require more time to participate than the estimate that the Commission provided in the Proposed Rule. However, the fact that such processes have been developed reflects the choice of the participants in those regional transmission planning processes on how to comply with the Commission's rules, it does not mean that the Commission's rules necessarily required such processes. For example, we note that public utility transmission providers may decide, in a particular region or between regions, to develop a regional transmission planning process that includes more objectives and procedures than the minimum set forth in this Final Rule, which may increase the number of hours necessary to participate. In any event, Arizona Public Service Company did not provide any estimates of the number of hours that it has taken to participate in its regional transmission planning processes, nor suggested alternative estimates. Thus, for the most part, the Commission adopts the burden estimates that it set out in the Proposed Rule.

827. As for the hourly rates of the employees, the Commission relies on average national salaries to develop hourly rates of the employees necessary to comply with the requirements adopted in this Final Rule. Again, we note that this is an average rate, and that rates may be higher or lower depending on the area of the country where the public utility transmission provider is located. Therefore, we find that the averages in the Proposed Rule are reasonable estimates of the average national rates for the employees described below.

828. Finally, the Commission has included, in its burden estimate, the number of hours that a public utility transmission provider may need to travel to participate in a regional transmission planning process and interregional transmission coordination procedures.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in this Final Rule follow.

FERC–917—Proposed reporting requirements in RM10–23	Annual number of respondents (filers)	Annual number of responses	Hours per response	Total annual hours in year 1	Total annual hours in subsequent years
Participation in a transparent and open regional transmission planning process that meets regional transmission planning principles, includes consideration of transmission needs driven by Public Policy Requirements, identifies and evaluates transmission facilities to meet needs, develops cost allocation method(s), and produces a regional transmission plan that describes and incorporates a cost allocation method(s) that meets the Commission's principles.	132	132	110 hrs in Year 1; 52 hrs in subsequent years.	14520	6864
Development of interregional transmission coordination procedures that meet the Commission's requirements, including the ongoing requirement to provide or post certain transmission planning information and provide annual data exchange, as well as the development of a cost allocation method for interregional transmission facilities that meets the Commission's principles.	132	132	133 hrs in Year 1; 43 hrs in subsequent years.	17556	5676
Conforming tariff changes for local transmission planning, including those related to consideration of transmission needs driven by Public Policy Requirements; and conforming tariff changes for regional transmission planning and interregional transmission coordination.	132	132	57 hrs in Year 1; 25 hrs in subsequent years.	7524	33000
Total Estimated Additional Burden Hours, Proposed for FERC–917 in NOPR in RM10–23.	....	....	....	39600	15840

Cost to Comply

Year 1: $4,514,400 or [39,600 hours × $114 per hour[583]]

Subsequent Years: $1,805,760 or [15,840 hours × $114 per hour]

Title: FERC–917.

Action: Proposed Collections.

OMB Control No: 1902–0233.

Respondents: Public Utility Transmission Providers. An RTO or ISO also may file some materials on behalf of its members.

Frequency of Responses: Initial filing and subsequent filings.

Necessity of the Information

829. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission adopts these amendments to the *pro forma* OATT to correct certain deficiencies in the transmission planning and cost allocation requirements for public utility transmission providers. The purpose of this Final Rule is to strengthen the *pro forma* OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just

[582] 5 CFR 1320.3(b)(1)–(2).

[583] The estimated cost of $114 an hour is the average of the hourly costs of: attorney ($200), consultant ($150), technical ($80), and administrative support ($25).

and reasonable and not unduly discriminatory or preferential. We expect to achieve this goal through this Final Rule by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

830. Interested persons may obtain information on reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: *Data Clearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax (202) 395–7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include OMB Control No. 1902–0233 and Docket No. RM10–23–000.

VII. Environmental Analysis

831. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[584] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed Rule because section 380.4(a)(15) of the Commission's regulations provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[585] The reforms herein do not require transmission or other facilities to be built, but rather establish transmission planning mechanisms that will result in a more appropriate allocation of costs and thus better ensure just and reasonable and not unduly discriminatory or preferential rates.

[584] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[585] 18 CFR 380.4(a)(15).

VIII. Regulatory Flexibility Act Analysis

832. The Regulatory Flexibility Act of 1980 (RFA) [586] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Final Rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890. The total number of public utility transmission providers that, absent waiver, must modify their current OATTs by filing the revised *pro forma* OATT is 132. Of these public utility transmission providers, only 9 filers, or 6.8 percent, have output of four million MWh or less per year.[587] The Commission does not consider this a substantial number and, in any event, each of these entities retains its rights to request waiver of these requirements. The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

IX. Document Availability

833. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

834. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

[586] 5 U.S.C. 601–612.

[587] A firm is ''small'' if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt-hours. Based on the filers of the annual FERC Form 1 and Form 1–F, as well as the number of companies that have obtained waivers, we estimate that 6.8 percent of the filers are ''small.''

835. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

X. Effective Date and Congressional Notification

836. These regulations are effective October 11, 2011. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit this Final Rule to both houses of Congress and the Government Accountability Office.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Moeller is dissenting, in part, with a separate statement attached.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 71–7352.

■ 2. Amend § 35.28 as follows:
■ a. Paragraphs (c)(1) through (c)(1)(iii) are revised.
■ b. Paragraph (c)(1)(vi) is revised.
■ c. Paragraphs (c)(3), (c)(3)(i), and (c)(3)(ii) are revised.
■ d. Paragraphs (c)(4) through (c)(4)(ii) are revised.
■ e. Paragraph (d)(1) is revised.
■ f. Paragraph (e)(1) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) *Non-discriminatory open access transmission tariffs.*

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services,

including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms) and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs ¶ 31,306, Order No. 890, FERC Stats. & Regs. ¶ 32,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of October 11, 2011, it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ 31,323.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of October 11, 2011, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

* * * * *

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs. ¶ 31,323, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after October 11, 2011, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before October 11, 2011, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff consistent with Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ 31,323.

* * * * *

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ 31,323.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Order No. 1000, FERC Stats. & Regs ¶ 31,323.

(d) * * *

(1) No later than October 11, 2011, or

* * * * *

(e) * * *

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

* * * * *

Note: The following appendices will not be published in the Code of Federal Regulations.

APPENDIX A—SUMMARY OF COMPLIANCE FILING REQUIREMENTS

Deadline (months after the effective date of the final rule)	Compliance action	Section of the final rule
12 months	Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include local and regional transmission planning processes that are consistent with the requirements of this Final Rule.	Section III.A.
12 months	Submit revised Attachment K of the *pro forma* OATT and other Commission jurisdictional documents to include a cost allocation method or methods for regional cost allocation consistent with principles of this Final Rule.	Section III.C.
18 months	Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include an interregional transmission coordination procedure or procedures consistent with the requirements of this Final Rule.	Section IV.C.
18 months	Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include a cost allocation method or methods for interregional cost allocation consistent with the principles of this Final Rule.	Section IV.D.

Appendix B: Abbreviated Names of Commenters

The following two tables contain the abbreviated names of initial and reply commenters that are used in this Final Rule.

INITIAL COMMENTERS

Abbreviation	Initial commenter(s)
26 Public Interest Organizations	Alliance for Clean Energy New York; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Earthjustice; Environment Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Institute for Market Transformation; Iowa Environmental Council; Land Trust Alliance; National Audubon Society; Natural Resources Defense Council; Pennsylvania Land Trust Alliance; Nevada Wilderness Project; NW Energy Coalition; Pace Energy and Climate Center; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; The Wilderness Society; Union of Concerned Scientists; and Western Grid Group.
Ad Hoc Coalition of Southeastern Utilities	Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company).
AEP	American Electric Power Service Corporation.
Alabama PSC	Alabama Public Service Commission.
Allegheny Energy Companies	Monongahela Power Company; The Potomac Edison Company; West Penn Power Company; Trans-Allegheny Interstate Line Company; and Allegheny Energy Supply Company, LLC.
ALLETE	ALLETE, Inc.
Alliant Energy	Alliant Energy Corporate Services, Inc.
American Antitrust Institute	American Antitrust Institute.
American Forest & Paper	American Forest & Paper Association.
American Transmission	American Transmission Company LLC.
Anbaric and PowerBridge	Anbaric Holding, LLC; PowerBridge, LLC.
APPA	American Public Power Association.
Arizona Corporation Commission	Arizona Corporation Commission.
Arizona Public Service Company	Arizona Public Service Company.
Atlantic Grid	Atlantic Grid Development, LLC on behalf of Atlantic Wind Connection.
Avista and Puget Sound	Avista Corporation and Puget Sound Energy, Inc.
AWEA	American Wind Energy Association; Wind on the Wires; Renewable Northwest Project; Mid-Atlantic Renewable Energy Coalition; Alliance for Clean Energy, Inc.; Interwest Energy Alliance; RENEW; the Wind Coalition; and Center for Energy Efficiency and Renewable Technologies.
Baltimore Gas & Electric	Baltimore Gas & Electric Company.
Bay Area Municipal Transmission Group	City of Santa Clara, California; the City of Palo Alto, California; and the City of Alameda, California.
Bonneville Power	Bonneville Power Administration.
Boundless Energy and Sea Breeze	Boundless Energy, LLC and Sea Breeze Pacific Regional Transmission System.
Brattle Group (The)	Peter Fox-Penner; Johannes Pfeifenberger; and Delphine Hou.
California Commissions	California Public Utilities Commission and the Energy Resources Conservation and Development Commission of the State of California.
California ISO	California Independent System Operator Corporation.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
California Municipal Utilities	California Municipal Utilities Association (Cities of Alameda; Anaheim; Azusa; Banning; Burbank; Cerritos; Colton; Corona; Glendale; Gridley; Healdsburg; Hercules; Lodi; Lompoc; Moreno Valley; Needles; Palo Alto; Pasadena; Pittsburg; Rancho Cucamonga; Redding; Riverside; Roseville; Santa Clara; Shasta Lake; Ukiah; and Vernon; the Imperial; Merced; Modesto; Turlock Irrigation Districts; the Northern California Power Agency; Southern California Public Power Authority; Transmission Agency of Northern California; Lassen Municipal Utility District; Power and Water Resources Pooling Authority; Sacramento Municipal Utility District; the Trinity and Truckee Donner Public Utility Districts; the Metropolitan Water District of Southern California; and the City and County of San Francisco, and Hetch-Hetchy).
California Transmission Planning Group	Sacramento Municipal Utility District; the Imperial Irrigation District; the Los Angeles Department of Water and Power; the Southern California Public Power Authority; the Transmission Agency of Northern California; the Turlock Irrigation District; the Southern California Edison Company; the Pacific Gas & Electric Company and the San Diego Gas & Electric Company.
California State Water Project	California Department of Water Resources State Water Project.
CapX2020 Utilities	Central Minnesota Municipal Power Agency; Dairyland Power Cooperative; Great River Energy; Minnesota Power; Minnkota Power Cooperative; Missouri River Energy Services; Otter Tail Power Company; Rochester Public Utilities; Southern Minnesota Municipal Power Agency; WPPI Energy; and Xcel Energy Inc.
Champlain Hudson	Champlain Hudson Power Express, Inc.
City and County of San Francisco	City and County of San Francisco.
City of Los Angeles Department of Water and Power.	City of Los Angeles Department of Water and Power.
City of Santa Clara	City of Santa Clara, California.
Clean Energy Group	Clean Energy Group.
Clean Line	Clean Line Energy Partners LLC.
Coalition for Fair Transmission Policy	CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Northeast Utilities; PPL Corporation; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company; United Illuminating Company.
Colorado Independent Energy Association	Colorado Independent Energy Association.
ColumbiaGrid	ColumbiaGrid (Avista Corporation; Bonneville Power Administration; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 1 of Snohomish County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; City of Tacoma, Department of Public Utilities, Light Division; and the City of Seattle, by and through its City Light Department).
Connecticut & Rhode Island Commissions	Connecticut Department of Public Utility Control and the Rhode Island Public Utilities Commission.
Conservation Law Foundation	Conservation Law Foundation.
Consolidated Edison and Orange & Rockland	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
Consumers Energy Company	Consumers Energy Company.
Dayton Power and Light	Dayton Power and Light Company (The).
DC Energy	DC Energy, LLC.
Delaware PSC	Delaware Public Service Commission.
Direct Energy	Direct Energy Services, LLC; Direct Energy Business, LLC; and Energy America, LLC.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation.
Duquesne Light Company	Duquesne Light Company.
EARTHJUSTICE	EARTHJUSTICE.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc.; Sam Rayburn G&T Electric Cooperative.
Eastern Massachusetts Consumer-Owned System.	Belmont Municipal Light Department; Braintree Electric Light Department; Concord Municipal Light Plant; Hingham Municipal Lighting Plant; Reading Municipal Light Department; Taunton Municipal Lighting Plant; and Wellesley Municipal Light Plant.
Edison Electric Institute	Edison Electric Institute.
EIF Management	EIF Management, LLC.
Electricity Consumers Resource Council and the Associated Industrial Groups.	Electricity Consumers Resource Council; American Chemistry Council; Association of Businesses Advocating Tariff Equity; Carolina Utility Customers Association; Coalition of Midwest Transmission Customers; Florida Industrial Power Users Group; Georgia Industrial Group-Electric; Industrial Energy Users—Ohio; Oklahoma Industrial Energy Consumers; PJM Industrial Customer Coalition; West Virginia Energy Users Group; and Wisconsin Industrial Energy Group.
Enbridge	Enbridge Inc.
Energy Consulting Group	Energy Consulting Group LLC (representing Central Georgia EMC; Cobb EMC; Diverse Power Incorporated; Pataula EMC; Snapping Shoals EMC; Upson EMC; and Washington EMC).
Energy Future Coalition Group	Energy Future Coalition; Alliance for Clean Energy New York, Inc.; American Wind Energy Association; BrightSource Energy, Center for American Progress, Conservation Law Foundation; Environmental Northeast; Fresh Energy; Interwest Energy Alliance; Invenergy Thermal Development, LLC; Invenergy Wind Development, LLC; ITC Holdings, Corp.; Mesa Power Group; Mid-Atlantic Renewable Energy Coalition; Natural Resources Defense Council; Renewable Northwest Project; Sierra Club; Solar Energy Industries Association; The FERC Project; The Stella Group, Ltd.; The Wilderness Society; Union of Concerned Scientists; Utility Workers Union of America; and Western Grid Group.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
Environmental Defense Fund	Environmental Defense Fund.
Environmental NGOs	Environmental Non-Governmental Organizations (Environmental Integrity Project; Izaak Walton League of America; Clean Air Council; Michigan Environmental Council; Ohio Citizen Action; Natural Resources Defense Council; Fresh Energy; Citizens for Pennsylvania's Future; Sierra Club; and Earthjustice).
E.ON	E.ON U.S. LLC.
E.ON Climate & Renewables North America	E.ON Climate & Renewables North America, LLC.
Exelon	Exelon Corporation.
Federal Trade Commission	Federal Trade Commission.
First Wind	First Wind Energy, L.L.C.
FirstEnergy Service Company	FirstEnergy Service Company, on behalf of FirstEnergy Companies: Ohio Edison Company; Pennsylvania Power Company; The Cleveland Electric Illuminating Company; The Toledo Edison Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; and Pennsylvania Electric Company, and FirstEnergy Solutions Corp. and their respective electric utility subsidiaries and affiliates.
Florida PSC	Florida Public Service Commission.
Four G&T Cooperatives	Associated Electric Cooperative; Basin Electric Power Cooperative; and Tri-State Generation and Transmission Association.
Gaelectric North America	Gaelectric North America.
Georgia Transmission Corporation	Georgia Transmission Corporation.
Governors of Delaware and Maryland	Governors of Delaware and Maryland.
Grasslands	Grasslands Renewable Energy LLC.
Green Energy and 21st Century	Green Energy Express LLC and 21st Century Transmission Holdings, LLC.
Grid Solar	Grid Solar, LLC.
Horizon Wind Energy	Horizon Wind Energy LLC.
Iberdrola Renewables	Iberdrola Renewables, Inc.
Ignacio Perez-Arriaga	Ignacio J. Perez-Arriaga.
Illinios Commerce Commission	Illinois Commerce Commission.
Imperial Irrigation District	Imperial Irrigation District.
Independent Energy Producers Association	Independent Energy Producers Association.
Indianapolis Power & Light	Indianapolis Power & Light Company.
Indicated PJM Transmission Owners	Monongahela Power Company; The Potomac Edison Company and West Penn Power Company; and Trans-Allegheny Interstate Line Company; Baltimore Gas and Electric Company; The Dayton Power and Light Company; Duquesne Light Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; Pennsylvania Electric Company; Pepco Holdings, Inc.; Potomac Electric Power Company; Delmarva Power & Light Company; Atlantic City Electric Company; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC; UGI Utilities, Inc.; and Virginia Electric and Power Company.
Integrated Transmission Benefits Model Proponents.	Maine PUC; Maine Office of the Public Advocate; Maine Office of Energy Independence and Security; New Hampshire Public Utilities Commission; Environment Northeast; and Conservation Law Foundation.
Integrys	Wisconsin Public Service Corporation; Upper Peninsula Power Company; and Integrys Energy Services, Inc.
Invenergy	Invenergy Wind Development LLC.
ISO New England	ISO New England Inc.
ISO/RTO Council	California Independent System Operator; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; Southwest Power Pool, Inc.
ITC Companies	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP.
Joint Commenters	American Chemistry Council; American Forest & Paper Association; American Public Power Association; California Municipal Utilities Association; California Public Utilities Commission; Electricity Consumers Resource Council; Indiana Utility Regulatory Commission; Modesto Irrigation District; Montana Public Service Commission; National Association of State Utility Consumer Advocates; New England Conference of Public Utility Commissioners; New Hampshire Office of Consumer Advocate; New Jersey Division of Rate Counsel; New York State Public Service Commission; Office of the Nevada Attorney General, Bureau of Consumer Protection; Old Dominion Electric Cooperative; Sacramento Municipal Utility District; South Dakota Public Utilities Commission; State of Maine, Office of the Public Advocate; Transmission Agency of Northern California; Utility Reform Network; Vermont Department of Public Service; and Vermont Public Service Board.
Kansas City Power & Light and KCP&L Greater Missouri.	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.
Kansas Corporation Commission	Kansas Corporation Commission.
Land Trust Alliance	Land Trust Alliance.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Los Angeles Department of Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities.
Long Island Power Authority	Long Island Power Authority.
LS Power	LS Power Transmission, LLC.
Maine PUC	Maine Public Utility Commission.
Maine Utilities	Bangor Hydro Electric Company; Central Maine Power Company; and Maine Public Service.
Massachusetts Departments	Massachusetts Department of Public Utilities and Massachusetts Department of Energy Resources.
Massachusetts Municipal and New Hampshire Electric.	Massachusetts Municipal Wholesale Electric Company and New Hampshire Electric Cooperative, Inc.
Michigan Citizens Against Rate Excess	Michigan Citizens Against Rate Excess.
MidAmerican	MidAmerican Energy Holdings Company.
MISO	Midwest Independent System Transmission Operator, Inc.
MISO Transmission Owners	Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); American Transmission Company LLC; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wolverine Power Supply Cooperative, Inc.
Minnesota PUC and Minnesota Office of Energy Security.	Minnesota Public Utilities Commission and Minnesota Office of Energy Security.
Modesto Irrigation District	Modesto Irrigation District.
Multiparty Commenters	American Electric Power Corp.; AWEA, Energy Future Coalition; Iberdrola Renewables; ITC Holdings Corp.; LS Power Transmission LLC; Mesa Power Group, LLC; NextEra Energy, Inc.; and SEIA.
NARUC	National Association of Regulatory Utility Commissioners.
National Audubon Society	National Audubon Society.
National Grid	National Grid USA.
National Rural Electric Coops	National Rural Electric Cooperative Association.
Natural Resources Defense Council	Natural Resources Defense Council.
Nebraska Public Power District	Nebraska Public Power District.
NEPOOL	New England Power Pool Participants Committee.
Nevada Hydro	Nevada Hydro Company.
New England States Committee on Electricity	New England States Committee on Electricity.
New England Transmission Owners	Bangor Hydro Electric Company; Central Maine Power Company; NSTAR Electric Company; New England Power Company; Northeast Utilities Service Company on behalf of the Northeast utilities system operating companies; The United Illuminating Company; and Vermont Electric Transmission Company, Inc., on behalf of itself and its affiliate, Vermont Transco LLC.
New Jersey Board	New Jersey Board of Public Utilities.
New Jersey Division of Rate Counsel	New Jersey Division of Rate Counsel.
New York ISO	New York Independent System Operator, Inc.
New York PSC	New York State Public Service Commission.
New York Transmission Owners	Central Hudson Gas & Electric; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
NextEra	NextEra Energy, Inc.
North Carolina Agencies	North Carolina Utilities Commission and Public Staff of the North Carolina Utilities Commission.
Northeast Utilities	Northeast Utilities Service Company.
Northern California Power Agency	Northern California Power Agency.
Northern Tier Transmission Group	Northern Tier Transmission Group.
Northwest & Intermountain Power Producers Coalition.	Calpine Corporation; Capital Power Operations; Constellation Energy Control & Dispatch; EverPower Renewables; Exergy Development Group; First Wind; Horizon Wind Energy; Invenergy; LS Power Associates; Ridgeline Energy; Shell Energy North America; TransAlta Marketing, Inc; and TransCanada.
NorthWestern Corporation (Montana)	NorthWestern Corporation (Montana).
NRG Companies	NRG Companies.
NV Energy	Nevada Power Company and Sierra Pacific Power Company.
Ohio Consumers' Counsel and West Virginia Consumer Advocate Division.	Ohio Consumers' Counsel and West Virginia Consumer Advocate Division.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
Oklahoma Corporation Commission	Oklahoma Corporation Commission.
Oklahoma Gas and Electric Company	Oklahoma Gas and Electric Company.
Old Dominion	Old Dominion Electric Cooperative.
Omaha Public Power District	Omaha Public Power District.
Organization of MISO States	Indiana Utility Regulatory Commission; Iowa Utilities Board; Michigan Public Service Commission; Minnesota Public Utilities Commission; Missouri Public Service Commission; Montana Public Service Commission; North Dakota Public Service Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission.
Pacific Gas and Electric Pattern Transmission	Pacific Gas and Electric Company Pattern Transmission LP.
Pennsylvania PUC	Pennsylvania Public Utility Commission.
PHI Companies	Pepco Holdings, Inc.; Potomac Electric Power Company; Delmarva Power & Light Company; and Atlantic City Electric Company.
Pioneer Transmission	Pioneer Transmission, LLC.
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex Corp.
PPL Companies	PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL RenewableEnergy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; and PPL Colstrip II, LLC.
Primary Power	Primary Power, LLC.
PSC of Wisconsin	Public Service Commission of Wisconsin.
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; and PSEG Energy Resources & Trade LLC.
Public Power Council	Public Power Council.
PUC of Nevada	Public Utility Commission of Nevada.
PUC of Ohio	Public Utility Commission of Ohio.
Sacramento Municipal Utility District	Sacramento Municipal Utility District.
Salt River Project	Salt River Project Agricultural Improvement and Power District.
San Diego Gas & Electric	San Diego Gas & Electric Company.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, CA.
Solar Energy Industries and Large-scale Solar	Solar Energy Industries Association and Large-scale Solar Association.
Sonoran Institute	Sonoran Institute.
South Carolina Electric & Gas	South Carolina Electric & Gas Company.
Southern California Edison	Southern California Edison Company.
Southern Companies	Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.
Southwest Area Transmission Subregional Planning Group.	Southwest Area Transmission Subregional Planning Group.
SPP	Southwest Power Pool, Inc.
Starwood	Starwood Energy Group Global, L.L.C.
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC.
Transmission Access Policy Study Group	Transmission Access Policy Study Group.
Transmission Agency of Northern California	Transmission Agency of Northern California.
Transmission Dependent Utility Systems	Arkansas Electric Cooperative Corporation; Golden Spread Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc.
Tucson Electric	Tucson Electric Power Company.
U.S. Senators Dorgan and Reid	United States Senators Byron Dorgan and Harry Reid.
Vermont Electric	Vermont Electric Power Company, Inc.
Virginia State Corporation Commission	Virginia State Corporation Commission.
Washington Utilities and Transportation Commission.	Washington Utilities and Transportation Commission.
WECC	Western Electricity Coordinating Council.
Westar	Westar Energy, Inc. and Kansas Gas and Electric Company.
WestConnect Planning Parties	Arizona Public Service Company; Basin Electric Power Cooperative; Black Hills Corporation; El Paso Electric Company; Imperial Irrigation District; NV Energy; Public Service Company of New Mexico; Sacramento Municipal Utility District; Salt River Project Agricultural Improvement and Power District; Southwest Transmission Cooperative, Inc.; Transmission Agency of Northern California; Tri-State Generation and Transmission Association, Inc.; Tucson Electric Power Company; and Western Area Power Administration.
Western Area Power Administration	Western Area Power Administration.
Western Grid Group	Western Grid Group.
Western Independent Transmission Group	Western Independent Transmission Group.
The Wilderness Society and Western Resource Advocates.	The Wilderness Society and Western Resource Advocates.
Wind Coalition (The)	Wind Coalition (The).
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.
Wisconsin Electric Power Company	Wisconsin Electric Power Company.
Xcel	Xcel Energy Services Inc.

REPLY COMMENTERS

Abbreviation	Reply commenter(s)
26 Public Interest Organizations	Citizens Utility Board of Wisconsin; Climate and Energy Project; CNT Energy; Conservation Law Foundation; Earth Justice; Energy Conservation Council of Pennsylvania; Energy Future Coalition; Environmental Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Institute for Market Transformation; Iowa Environmental Council; Land Trust Alliance; Midwest Energy Efficiency Alliance; National Audubon Society; Natural Resources Defense Council; Northeast Energy Efficiency Partnerships; NW Energy Coalition; Pace Energy and Climate Center; Pennsylvania Land Trust Association; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; The Wilderness Society; Union of Concerned Scientists; Western Grid Group; Western Resource Advocates; Wind on the Wires.*[588]
Ad Hoc Coalition of Southeastern Utilities	Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; Louisville Gas & Electric Company and Kentucky Utilities Company; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company).*
AEP	American Electric Power Service Corporation.
Alabama Municipal Electric Authority	Alabama Municipal Electric Authority.
APPA	American Public Power Association.
Arizona Public Service Company	Arizona Public Service Company.
Atlantic Grid	Atlantic Grid Development, LLC, on behalf of Atlantic Wind Connection.
Baltimore Gas & Electric	Baltimore Gas and Electric Company.
Bay Area Municipal Transmission Group	City of Santa Clara, California; the City of Palo Alto, California; the City of Alameda, California.
Bonneville Power	Bonneville Power Administration.
California ISO	California Independent System Operator Corporation.
California PUC	California Public Utilities Commission.
California Transmission Planning Group	Sacramento Municipal Utility District; the Imperial Irrigation District; the City of Los Angeles Department of Water and Power; the Southern California Public Power Authority; the Transmission Agency of Northern California; the Turlock Irrigation District; the Southern California Edison Company; the Pacific Gas & Electric Company; San Diego Gas & Electric Company.
City of Santa Clara	City of Santa Clara, California.
Coalition for Fair Transmission Policy	CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Northeast Utilities; PPL Corporation; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company; United Illuminating Company.
Commissioner Nathan A. Skop of the Florida PSC.	Commissioner Nathan A. Skop of the Florida PSC.
Conservation Law Foundation	Conservation Law Foundation.
Consolidated Edison and Orange & Rockland	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
EarthJustice and Environmental Groups	EARTHJUSTICE; Environmental Integrity Project; Natural Resources Defense Council; Environmental Law & Policy Center; Fresh Energy.
EarthJustice *et al.*	EARTHJUSTICE on behalf of Sierra Club; Natural Resources Defense Council; National Rural Electric Coops; Citizens for Pennsylvania's Future.
Eastern Environmental and Conservation Groups.	New Jersey Highlands Coalition; New Jersey Chapter of the Sierra Club; Delaware Riverkeeper Network; New Jersey Conservation Foundation; Stop the Lines.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc.; Sam Rayburn G&T Electric Cooperative.
Edison Electric Institute	Edison Electric Institute.
EIF Management	EIF Management, LLC.
Entergy	Entergy Services Inc., on behalf of the Entergy Operating Companies (Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.
Environmental Defense Fund	Environmental Defense Fund.
Exelon	Exelon Corporation.
First Wind	First Wind Energy, L.L.C.
Florida PSC	Florida Public Service Commission.
Green Energy and 21st Century	Green Energy Express LLC and 21st Century Transmission Holdings, LLC.
H–P Energy Resources	H–P Energy Resources LLC.
Identified New England Transmission Owners	Identified New England Transmission Owners.
Illinois Commerce Commission	Illinois Commerce Commission.
ISO New England	ISO New England Inc.
ISO/RTO Council	California Independent System Operator; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; Southwest Power Pool, Inc.
ITC Companies	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP.

REPLY COMMENTERS—Continued

Abbreviation	Reply commenter(s)
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; Tacoma Public Utilities.
LS Power	LS Power Transmission, LLC.
Maine Parties	Maine Public Utilities Commission; Maine Office of the Public Advocate; Maine Governor's Office of Energy, Independence and Security.
MEAG Power	MEAG Power.
MISO Transmission Owners	Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); American Transmission Company LLC; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wolverine Power Supply Cooperative, Inc.
Multiparty Commenters	American Electric Power Corp.; AWEA; Energy Future Coalition; Iberdrola Renewables; ITC Holdings Corp.; LS Power Transmission LLC; Mesa Power Group, LLC; NextEra Energy, Inc.; SEIA; and Western Grid Group.*
National Grid	National Grid USA.
National Rural Electric Coops	National Rural Electric Cooperative Association.
New England States Committee on Electricity	New England States Committee on Electricity.
New Jersey Board	New Jersey Board of Public Utilities.
New York Transmission Owners	Central Hudson Gas & Electric; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
NextEra	NextEra Energy, Inc.
North Dakota and South Dakota Commission	North Dakota Public Service Commission and South Dakota Public Utilities Commission.
Ohio Consumers' Counsel	Office of the Ohio Consumers' Counsel.
Old Dominion	Old Dominion Electric Cooperative.
Organization of MISO States	Illinois Commerce Commission; Indiana Utility Regulatory Commission; Iowa Utilities Board; Michigan Public Service Commission; Minnesota Public Utilities Commission; Missouri Public Service Commission; Montana Public Service Commission; North Dakota Public Service Commission; Public Utilities Commission of Ohio; Pennsylvania Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission.*
Pacific Gas and Electric	Pacific Gas and Electric Company.
Pattern Transmission	Pattern Transmission LP.
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex Corp.
PPL Companies	PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL RenewableEnergy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; PPL Colstrip II, LLC; PPL Maine, LLC; PPL Wallingford Energy LLC.*
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC.
Sacramento Municipal Utility District	Sacramento Municipal Utility District.
San Diego Gas & Electric	San Diego Gas & Electric Company.
Sierra Club	8,203 Sierra Club members, supporters, and electric system ratepayers.
Solar Energy Industries and Large-scale Solar	Solar Energy Industries Association and Large-scale Solar Association.
South Carolina Office of Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern California Edison	Southern California Edison Company.
Southern Companies	Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.
Southern New England States	Southern New England States.
Transmission Agency of Northern California	Transmission Agency of Northern California.
Western Independent Transmission Group	Western Independent Transmission Group.
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.

Appendix C: *Pro Forma* Open Access Transmission Tariff

Pro Forma OATT

Attachment K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in Order No. 890: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The planning process also shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The description of the Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

Nothing in the regional transmission planning process shall include an unduly discriminatory or preferential process for transmission project submission and selection.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for transmission customers to submit data;

(vi) Process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation;

(vii) Process for submission of data by merchant transmission developers that wish to participate in the transmission planning process;

(viii) The dispute resolution process;

(ix) The study procedures for economic upgrades to address congestion or the integration of new resources;

(x) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000.

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000.

MOELLER, Commissioner, *dissenting in part*:

While I offer substantial praise for this final rule, the Commission should have taken a different approach to several important issues. But before addressing these issues, we must recognize that all of the nation's difficulties in building needed transmission will not be resolved by this rule. Rather, this rule largely addresses planning for long-distance transmission lines, which is only a subset of the critical issues that are inhibiting needed investment.

[588] A "*" indicates that the composition of this group as altered in the reply comment filing.

This rule cannot address issues like the delays caused by other federal agencies in the siting of important projects, as this Commission lacks the legal authority to require other federal agencies to act.[589] And this rule also cannot address issues of state law, regardless of the reliability needs that are served by a new transmission line. Moreover, and as described further below, this rule did not address whether a transmission provider can thwart competitive options by refusing to upgrade its transmission system. For these reasons, this rule will not resolve all of the difficult issues that discourage this nation from constructing needed transmission lines.

Regarding the issues that the final rule does address, I believe that the owner of a transmission network should have been provided with greater flexibility to ensure the reliability of its own network. Moreover, the rule should have clarified that a right of first refusal is not a right of ''forever'' refusal. That is, a right to ''forever'' block a needed transmission project could prevent the lowest-cost power from reaching consumers.

To encourage needed transmission investment, the final rule permits incumbent transmission owners to maintain their existing rights of first refusal for: (1) local projects where the incumbent does not seek to share the costs of those projects; (2) upgrades to existing assets; and (3) projects on existing right of way.[590] However, notably absent from these categories of projects is the right of a utility to build a project within its franchised service territory in order to maintain the reliability of its existing network—regardless of whether the cost of that project is allocated on a regional basis.

In my view, transmission providers should have been entitled under the final rule to maintain their rights of first refusal to build a new transmission facility that is: (1) located entirely within the provider's franchised service territory; and (2) identified by the provider as needed to satisfy NERC reliability standards—even if that facility is selected in a regional transmission plan for purposes of cost allocation. And because a transmission provider would have retained its authority to address reliability issues in its franchised service territory, the final rule would not have needed its blanket waiver of penalties in the event that a competitor fails to fix a reliability issue.[591]

Had we allowed all reliability projects within a franchised service territory to retain a right of first refusal, this Commission would have emphasized its commitment to reliability. An incumbent transmission provider should be responsible for reliability needs in its franchised territory without regard to cost allocation. And by granting a blanket waiver of penalties, the final rule could be placing the Commission in a difficult position if a blackout results in widespread loss of power, and we are unable to assess a penalty.

My approach also would have encouraged transmission owners to seek regional cost allocation for their own local projects as a way of balancing regional costs. Such a balancing of projects could help ensure that all the parts of a region receive benefits that are at least roughly equivalent. Yet under the final rule, local projects that have their costs assigned regionally generally cannot maintain a right of first refusal, thus discouraging transmission owners from seeking regional cost allocation for their local projects. For this reason, instead of encouraging more regional cooperation, the rule could ultimately discourage such cooperation by encouraging more local transmission projects.

In addition to my concerns regarding reliability, this Commission should have clarified that it was willing to protect the energy markets against misuse of the right of first refusal. That is, the Commission should have emphasized that a right of first refusal in a Commission-jurisdictional tariff is not license to effectively block, or endlessly delay building, a project that would efficiently and cost effectively provide significant benefits to a transmission network. While an incumbent utility with a right of first refusal is entitled to have the ability to exercise its initial right to develop a project, if it decides not to construct, the opportunity to construct the project and thus improve the power grid should be available to a non-incumbent developer.

A review of the transmission projects that have been adopted in various regional plans indicates that most projects will be allowed to retain the right of first refusal under the final rule, as most projects involve upgrades to existing assets, or they are built on an existing right of way, or their costs are not allocated to other transmission providers.[592] Thus, given the extensive number of projects that will be allowed to retain a right of first refusal, the Commission should have emphasized that a transmission provider cannot use a Commission-jurisdictional [593] tariff to prevent the lowest-cost power from reaching consumers.

Recognizing that no party to this proceeding asserted that a right of first refusal grants its holder a right to refuse building a project forever, I believe that a federal right of first refusal must be exercised within a reasonable time frame. The record in this case suggests that 90 days is a reasonable time frame for management to make a decision on whether to exercise its right to build a project.[594] While adoption of a 90-day time frame for transmission providers need not have been mandated, the Commission should have encouraged every region to adopt a time frame that

[589] See the comments of PJM at 17, which state that, ''[t]he PJM Board approved the Susquehanna-Roseland 500 kV line in 2007. The Susquehanna-Roseland line was approved by the state regulatory commissions in Pennsylvania and New Jersey for 2012. The line is currently delayed by the National Parks Service [sic] and is not expected to be in service until 2014 at the earliest.''

[590] Section III.B.3.d of the final rule, at PP 318–319.

[591] For a description of the blanket waiver, see section III.B.4.b of the final rule, at P 344 (''Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.'')

[592] For a list of transmission projects that have been approved in PJM, see the various plans for PJM, and a comprehensive list available at: *http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx*. And see Chapter 8 of CAISO's transmission plan for 2010–2011 dated May 18, 2011, available at: *http://www.caiso.com/Documents/Board-approvedISO2010-2011TransmissionPlan.pdf*.

[593] Consistent with the remainder of the rule, any time limitation on a right of first refusal under my approach would be subject to relevant state and other law concerning property rights, contracts, utility franchises, zoning, siting, permitting, easements, or rights of way. *See* section III.B.2.c of the final rule, at P 287.

[594] Comments of Southwest Power Pool at 14–27; AEP Comments at 3, 19; Comments of Edison Electric Institute at 46–47, Comments of Iberdrola Renewables at 23–24; Comments of Indianapolis Power & Light at 32; MidAmerican Comments at 24; Comments of MISO Transmission Owners at 73; Comments of Oklahoma Gas and Electric Co., at 1, 12, 25; SCE Comments at 41–43; PSEG Reply Comments at 12; Westar Comments at 6; Comments of ITC Companies at 4, 22; Comments of CapX2020 Utilities at 11, where the CapX2020 Utilities consist of Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Co., Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy Inc. In contrast to these comments on a 90-day time limit, LS Power and NextEra object to any right of first refusal and state that a 90-day limitation does not resolve their objections. LS Power Comments at 14–18 and fn. 20; LS Power Reply Comments at 10, 34–35; and NextEra Comments at 16.

best reflects the needs and circumstances of that region.[595]

In conclusion, new transmission lines can sometimes be the lowest-cost way to improve the delivery of electricity. By building needed transmission, our nation's transmission network can be maintained at reliability levels that are the envy of the world, while simultaneously improving consumer access to lower-cost power generation. Plus, a well-designed transmission network can allow efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power. While this rule moves us forward to achieve those goals, a different approach would have been better on the issues described above.

[595] For example, in the case of the SPP region, the regional transmission organization will designate another company to build a project if the incumbent decides not to build within 90 days. Comments of Southwest Power Pool at 14–27.

Philip D. Moeller

Commissioner

[FR Doc. 2011–19084 Filed 8–10–11; 8:45 am]

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Part III

Department of Homeland Security

Coast Guard

46 CFR Parts 2, 15, 136, *et al.*
Inspection of Towing Vessels; Proposed Rule

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

46 CFR Parts 2, 15, 136, 137, 138, 139, 140, 141, 142, 143, and 144

[Docket No. USCG–2006–24412]

RIN 1625–AB06

Inspection of Towing Vessels

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to establish safety regulations governing the inspection, standards, and safety management systems of towing vessels. The proposal includes provisions covering: Specific electrical and machinery requirements for new and existing towing vessels, the use and approval of third-party auditors and surveyors, and procedures for obtaining Certificates of Inspection.

Without making a specific proposal at this time, the Coast Guard also seeks additional data, information and public comment on potential requirements for hours of service or crew endurance management for mariners aboard towing vessels. The Coast Guard would later request public comment on specific hours of service or crew endurance management regulatory text if it seeks to implement such requirements.

The intent of the proposed rulemaking is to promote safer work practices and reduce casualties on towing vessels by requiring that towing vessels adhere to prescribed safety standards and safety management systems or to an alternative, annual Coast Guard inspection regime. The Coast Guard promulgates this proposal in cooperation with the Towing Vessel Safety Advisory Committee and pursuant to the authority granted in section 415 of the Coast Guard and Maritime Transportation Act of 2004.

DATES: Comments and related material must either be submitted to our online docket via *http://www.regulations.gov* on or before December 9, 2011 or reach the Docket Management Facility by that date. Comments sent to the Office of Management and Budget (OMB) on collection of information must reach OMB on or before November 9, 2011.

ADDRESSES: You may submit comments identified by docket number USCG–2006–24412 using any one of the following methods:

(1) *Federal eRulemaking Portal: http://www.regulations.gov.*

(2) *Fax:* 202–493–2251.

(3) *Mail:* Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001.

(4) *Hand delivery:* Same as mail address above, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The telephone number is 202–366–9329.

To avoid duplication, please use only one of these methods. For instructions on submitting comments, *see* the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section below.

Collection of Information Comments: If you have comments on the collection of information discussed in section VI.D. ''Collection of Information'' of this NPRM, you must also send comments to the Office of Information and Regulatory Affairs (OIRA), OMB. To ensure that your comments to OIRA are received on time, the preferred methods are by e-mail to *oira_submission@omb.eop.gov* (include the docket number and ''Attention: Desk Officer for Coast Guard, DHS'' in the subject line of the e-mail) or fax at 202–395–6566. An alternate, though slower, method is by U.S. mail to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, ATTN: Desk Officer, U.S. Coast Guard.

Viewing incorporation by reference material: You may inspect the material proposed for incorporation by reference at Room 1210, U.S. Coast Guard Headquarters, 2100 Second Street, SW., Washington, DC 20593–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The telephone number is 202–372–1427. Copies of the material are available as indicated in the ''Incorporation by Reference'' section of this preamble.

FOR FURTHER INFORMATION CONTACT: If you have questions on this proposed rule, call Michael Harmon, Project Manager, CGHQ–1210, Coast Guard, telephone 202–372–1427. If you have questions on viewing or submitting material to the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Table of Contents for Preamble

I. Public Participation and Request for Comments

We encourage you to participate in this rulemaking by submitting comments and related materials. All comments received will be posted, without change, to *http://www.regulations.gov* and will include any personal information you have provided.

A. Submitting Comments

If you submit a comment, please include the docket number for this rulemaking (USCG–2006–24412), indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online, or by fax, mail or hand delivery, but please use only one of these means. We recommend that you include your name and a mailing address, an e-mail address, or a phone number in the body of your document so that we can contact you if we have questions regarding your submission.

To submit your comment online, go to *http://www.regulations.gov,* select the

Advanced Docket Search option on the right side of the screen, insert ''USCG–2006–24412'' in the Docket ID box, press Enter, and then click on the balloon shape in the Actions column. If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit them by mail and would like to know that they reached the Facility, please enclose a stamped, self-addressed postcard or envelope.

We will consider all comments and material received during the comment period and may change this proposed rule based on your comments.

B. Viewing Comments and Documents

To view comments, as well as documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* select the Advanced Docket Search option on the right side of the screen, insert USCG–2006–24412 in the Docket ID box, press Enter, and then click on the item in the Docket ID column. If you do not have access to the Internet, you may view the docket online by visiting the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. We have an agreement with the Department of Transportation to use the Docket Management Facility. Some articles we have referenced in the preamble are copyrighted and therefore we did not place a copy of these articles in our online docket. You may, however, either use the citation information we provided to obtain a copy of those articles or you may view a copy in room 1210, U.S. Coast Guard Headquarters, 2100 Second Street SW., Washington, DC 20593–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The telephone number is 202–372–1427.

C. Privacy Act

Anyone can search the electronic form of comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, *etc.*). You may review a Privacy Act notice regarding our public dockets in the January 17, 2008 issue of the **Federal Register** (73 FR 3316).

D. Public Meeting

We plan to hold public meetings on this NPRM. A notice with the specific dates and locations of the meetings will be published in the **Federal Register** as soon as this information is known. In addition, known interested parties will be contacted via mail, e-mail, or telephone. If you wish to be contacted regarding the public meetings, contact Mr. Michael Harmon, listed under **FOR FURTHER INFORMATION CONTACT**.

II. Abbreviations

ABS American Bureau of Shipping
ABSG American Bureau of Shipping Group
ABYC American Boat and Yacht Council
ACAPT Accredited for Commercial Assistance and Professional Towing
ACOE Army Corps of Engineers
ACP Alternate Compliance Program
AED Automatic External Defibrillator
ANSI American National Standards Institute
AWO American Waterways Operators
CEMS Crew Endurance Management System
CGMTA 2004 The Coast Guard and Maritime Transportation Act of 2004
COI Certificate of Inspection
COLREGS International Regulations for Prevention of Collisions at Sea
COTP Captain of the Port
DHS Department of Homeland Security
DOD Department of Defense
DOT Department of Transportation
EPIRB Emergency Position Indicating Radio Beacon
FAST Fatigue Avoidance Scheduling Tool
FMCSA Federal Motor Carrier Safety Administration
FR **Federal Register**
FRA Federal Railroad Administration
GAO Government Accountability Office
gpm Gallons Per Minute
IMO International Maritime Organization
ISM International Safety Management
ISO International Organization for Standardization
kPa Kilopascals
LBP Length Between Perpendiculars
LCG Longitudinal Center of Gravity
LORAN Long Range Aid to Navigation
LPM Liters Per Minute
MMC Merchant Mariner Credential
MOU Memorandum of Understanding
MSHA Mine Safety and Health Administration
MTSA Maritime Transportation Security Act of 2002
NARA National Archives and Records Administration
NEC National Electric Code
NFPA National Fire Protection Association
NIOSH National Institute for Occupational Safety and Health
NPRM Notice of Proposed Rulemaking
NTSB National Transportation Safety Board
OCMI Officer in Charge, Marine Inspection
OIRA Office of Information and Regulatory Affairs
OMB Office of Management and Budget
PA Public-Address
PE Professional Engineer
PPE Personal Protective Equipment
psi pounds per square inch
§ Section
SAE Society of Automotive Engineers
SIR and SIRE Ship Inspection Report
SOLAS International Convention for the Safety of Life at Sea, 1974
TSAC Towing Safety Advisory Committee
TSMS Towing Safety Management System
TVR Towing Vessel Record
UL Underwriters Laboratories Standard
U.S.C. United States Code
UWILD Underwater Inspection in Lieu of Dry Docking
VCG Vertical Center of Gravity
VHF–FM Very High Frequency-Frequency Modulated
VTS Vessel Traffic Service
WSE Water Surface Elevations

III. Background

A. Statutory History

The Coast Guard and Maritime Transportation Act of 2004 (CGMTA 2004), Public Law 108–293, 118 Stat. 1028, (Aug. 9, 2004), established new authorities for towing vessels as follows:

Section 415 added towing vessels, as defined in section 2101 of title 46, United States Code (U.S.C.), as a class of vessels that are subject to safety inspections under chapter 33 of that title (*Id.* at 1047).

Section 415 also added new section 3306(j) of title 46, authorizing the Secretary of Homeland Security to establish, by regulation, a safety management system appropriate for the characteristics, methods of operation, and nature of service of towing vessels (*Id.*).

Section 409 added new section 8904(c) of title 46, U.S.C., authorizing the Secretary to establish, by regulation, ''maximum hours of service (including recording and recordkeeping of that service) of individuals engaged on a towing vessel that is at least 26 feet in length measured from end to end over the deck (excluding the sheer).'' (*Id.* at 1044–45).

The House of Representatives published a Conference Report discussing these provisions, and in particular noted the Coast Guard's broad authority to regulate not just maximum hours of service but also provide predictable work and rest schedules, while considering circadian rhythms and human sleep and rest requirements. H.R. Conf. Rep. 108–617, 2004 U.S.C.C.A.N. 936, 951.

B. Regulatory History

On December 30, 2004, the Coast Guard published a Notice; request for comments, and notice of public meetings titled ''Inspection of Towing Vessels'' in the **Federal Register** (69 FR 78471). The notice asked seven questions regarding how the Coast Guard should move forward with the rulemaking to implement the statutory provisions from the CGMTA 2004, listed above in section III.A. ''Statutory History.'' The Coast Guard then held four public meetings, one each in Washington, DC, Oakland, CA, New Orleans, LA, and St. Louis, MO. In addition to the comments the Coast Guard received at the public meetings, there were 117 comments submitted to the docket, which can be found in docket [USCG–2004–19977] at *http://www.regulations.gov/search/index.jsp.* A majority of the comments answered the seven questions; however, some brought up issues outside the scope of the questions. These seven questions, as well as the summary of the comments that the Coast Guard received in response, can be found below in section IV.K. ''Discussion of Comments.''

C. American Bureau of Shipping Group (ABSG) Consulting Uninspected Towing Vessel Industry Analysis Report (ABSG Report)

The Coast Guard contracted with American Bureau of Shipping Group (ABSG) Consulting in the summer of 2006 for assistance with gathering data and categorizing the vessels that make up the towing industry. The 1-year effort included an analysis of casualty data, evaluating towing vessel accident history data from 1994 to 2003. ABSG evaluated the effects of the current policy (having no formal Coast Guard inspection program) on the various categories of towing vessels, and forecasted the effects Coast Guard inspections might have for the same vessels. This included preliminary costs of known regulatory alternatives.

To complete the ABSG Report, ABSG and Coast Guard personnel conducted visits to various towing companies, met with company officials and mariners, boarded towing vessels, and reviewed existing safety management systems. The companies visited varied in size and industry segment and included those operating on the West, Gulf, and Atlantic coasts, and along the Western Rivers. The final report was used to draft portions of the proposal published in this document. The final ABSG Report is available in the docket for this NPRM, and can be found by following the instructions listed above in section I.B. ''Viewing comments and documents.''

D. Towing Safety Advisory Committee (TSAC)

In the fall of 2004, the Coast Guard requested that the Towing Safety Advisory Committee (TSAC) assist in developing an inspection regimen for towing vessels. The TSAC is a Federal advisory committee to the Coast Guard that represents the towing and barge industry, with members from the mineral and oil supply vessel industry, port districts, authorities and terminal operators, maritime labor, shippers, and the general public. TSAC members come from large towing companies as well as the small business towing community, and represent a wide cross section of viewpoints from the industry.

TSAC established a working group that consisted of individuals from across the industry. Since 2004, nearly 200 individuals contributed to the deliberations of this working group, which were compiled into four reports, all of which were approved by the TSAC. The Coast Guard carefully reviewed each report, drafted concept documents, and submitted notional regulatory language for review with TSAC. Each submission of the Coast Guard's concepts and TSAC's subsequent reports prompted revisions that allowed the concepts to evolve to form the basis of the proposals published in this document. Each TSAC report is available in the docket for this NPRM, and can be found by following the instructions listed above in section I.B. ''Viewing comments and documents.''

While this process lengthened the overall time it took to complete this NPRM, it enabled the Coast Guard to achieve specific goals. First, the process allowed the Coast Guard to review ideas from industry representatives and discuss their issues and concerns. Furthermore, it allowed the towing industry to participate in the rulemaking process from the initial planning stages, as opposed to waiting until after the publication of an NPRM. This process also helped the Coast Guard create a comprehensive set of rules that the Coast Guard believes will ensure greater safety within the industry and that better represent the industry's uniqueness.

IV. Discussion of Proposed Rule

A. Summary

The Coast Guard proposes to establish a comprehensive safety system that includes company compliance, vessel compliance, vessel standards, and oversight in a new Code of Federal Regulations subchapter dedicated to towing vessels.

At the management level, organizations that operate towing vessels subject to inspection would be required to select a compliance option for the managed fleet. Those compliance options are a Safety Management System, including the development and implementation of that system, or an alternative annual Coast Guard inspection regime, leaving those vessels or fleets subject to an annual Coast Guard inspection. The safety management system would describe procedures for ensuring how its vessels and employees would comply with all applicable requirements prescribed in this subchapter. Management would tailor its safety management system to take into consideration its size, organizational structure, and vessel types and services. Towing Safety Management System (TSMS) compliance would be verified through audits and surveys conducted by third-party organizations approved by the Coast Guard and would be documented by the issuance of a TSMS Certificate.

At the vessel level, towing vessels operating under the TSMS option would receive audits and surveys by the approved third-party organizations, at a frequency delineated in part 138. In addition, the Coast Guard would conduct compliance examinations at least once every 5 years, along with additional random compliance checks based on risk. That risk would be determined through analysis of management and vessel safety histories. Certificates of Inspection (COIs) would be issued by the Coast Guard to vessels based on evidence of a vessel's successful compliance with the subchapter.

The Coast Guard would provide direct oversight of the third-party organizations that conduct TSMS audits and surveys, through approval and observation. This would include review and approval of the organization's application to become an approved third party, as well as review of the individual auditors and surveyors they employ. Random visits to their offices and direct observation of their activities would also be used. The Coast Guard would be able to consider an organization's history when evaluating requests for renewal of their status as an approved third party every 5 years and would also have the authority to revoke approval for failure to comply with conditions of approval and applicable standards.

Overall, this proposal would allow each towing vessel organization to customize its approach to meeting the requirements of the regulations, while providing continuous oversight using audits, surveys, inspections, and reviews of safety data. This would improve the safety of towing vessels and provide a more efficient means to use the resources of towing vessel operators, safety professionals in the approved third-party organizations, and the Coast Guard.

The Coast Guard understands that the majority of towing vessel accidents are related to human factors. We are proposing to address human factors in several ways. First, we propose to require that towing vessels be operated pursuant to a safety management system or be subject to an alternative, annual Coast Guard inspection regime. Second, we propose the establishment of new requirements directed at crew and vessel operational safety standards. As indicated below, in section IV.L. of the preamble, we are considering including hours of service standards and crew endurance management requirements but are not proposing such requirements at this time.

Equipment failures also contribute to towing accidents. We would address these non-human factors casualties by establishing vessel equipment and system standards appropriate for towing vessels, and by establishing procedures and schedules for routine tests and inspections of the vessels and their onboard equipment and systems.

In the remainder of this section (IV.), we summarize some of the significant portions of the NPRM, including the proposed applicability of the NPRM, the safety management system, the use of third parties, and the machinery and electrical provisions. After those summaries, we have broken down the proposed regulation in a part-by-part summary. We have included brief discussions on the topics of user fees and manning, as the NPRM contains changes to those already existing provisions in our regulations. Lastly, we have included a discussion of the comments we received in response to our December 30, 2004 request for comments (69 FR 78471).

B. Applicability

Congress did not expressly provide the Coast Guard with the authority to exempt from inspection any subset of vessels that perform towing (46 U.S.C. 3301(15)). However, Congress intended that the Coast Guard prescribe different standards for the various types of towing vessels based on size, horsepower, type of operation, or area of operation (H.R. Conf. Rep. 108–617, 2004 U.S.C.C.A.N. 936, 953), including requiring safety management systems appropriate for the characteristics, methods of operation, and nature of service of towing vessels. *See* 46 U.S.C. 3306(j).

After consulting with towing vessel industry representatives and analyzing data, the Coast Guard believes that focusing our initial efforts on inspecting those towing vessels moving commercial barges, especially those towing oil or other dangerous and combustible cargoes, and/or providing harbor assist services to large commercial ships, is reasonable because the preponderance of casualties reviewed by the Coast Guard involved these vessels, and the potential for casualties that cause permanent injury or death to humans, economic impact to the maritime transportation sector, and/or environmental damage is greatest due to the nature of their service. Therefore, the Coast Guard proposes that this rule not apply to: Towing vessels less than 26 feet in length, unless towing a barge carrying oil or other dangerous or combustible cargo in bulk; workboats that do not engage in commercial towing for hire, but may intermittently move a piece of equipment within a work site such as a dredging or construction site; and towing vessels performing assistance towing as currently defined in 46 CFR 10.107. Regulations covering these towing vessels would be proposed in a future regulatory project. The Coast Guard believes that staggering implementation of inspection requirements for towing vessels in this way allows us to focus our initial regulatory efforts on the characteristics that the groups have in common and the risks, noted above, that can lead to marine casualties.

Also, the proposed regulations for 46 CFR subchapter M, consisting of parts 136 through 144, would not apply to seagoing towing vessels of over 300 gross tons, as they are already subject to inspection as seagoing motor vessels under 46 CFR subchapter I. In 46 CFR 90.05–1 for subchapter I, and in other 46 CFR subchapters with a table that identifies what subchapter a vessel is inspected under, the Coast Guard will conform the table to reflect the change in towing vessels moving from an uninspected vessel class to a class of vessel inspected under 46 CFR subchapter M.

C. Towing Safety Management System (TSMS)

In this NPRM, the Coast Guard proposes to require towing vessels subject to this rulemaking to be part of a safety management system or be subject to an alternative, annual Coast Guard inspection regime. For the purposes of this proposed rule, a safety management system for towing vessels will be a Towing Safety Management System (TSMS). The objectives of a TSMS are to ensure the safety of the vessel and crew, prevent human injury or loss of life, avoid environmental and property damage, and ensure continuous compliance with applicable regulations. To accomplish these objectives, a TSMS would require management, in this case an owner or managing operator of a towing vessel, to implement safety management practices for both their shoreside management and vessel operations.

Congress provided authority to the Coast Guard to establish a safety management system appropriate for the characteristics, methods of operation, and nature of service of towing vessels (46 U.S.C. 3306(j)) and in section 701(c) of the Coast Guard Authorization Act of 2010 (Pub. L. 111–281), it directed the issuance of an NPRM based on that authority. The National Transportation Safety Board recommended establishing a safety management system appropriate for towing vessels (NTSB Safety Recommendation M–07–6). Furthermore, in its September 7, 2006 report on Towing Vessel Inspection, the Towing Safety Advisory Committee Working Group stated that a requirement for a safety management system should be ''* * * the cornerstone of the new inspection regime for towing vessels * * *'' (A copy of this document may be found in the docket for this rulemaking. Instructions for accessing the docket are found in section I.B. ''Viewing comments and documents.'')

The ABSG report, discussed in section III.C, recommended alternative inspection approaches for some companies stating, in part, that ''* * * a safety management system may not [be] a very cost-effective way to achieve safer operations, * * *'' and suggested a more traditional inspected vessel option be considered. In addition, pages 2–8 of the ABSG report stated ''* * * the industry personnel were clear that effective implementation of a safety management system was a very difficult task for a company that had not previously been highly structured and had not formally documented its policies and procedures.'' Also, page 21 of the TSAC Economic Working Group report stated ''[A SMS] will likely have a larger and more devastating impact on smaller companies who do not have the economic means, manpower, or even time to implement a system.''

However, considering the strong recommendations of both the NTSB and TSAC, and considering that towing vessels operate within the same areas as other vessels, many of which also use a safety management system, sharing busy waterways and overworked infrastructure, interacting within the supply chain and marine transportation system, and at times, sharing crewmembers, it is appropriate to propose that all towing vessels subject to this rulemaking have the option of operating within a company-implemented TSMS.

All towing companies, whether they are aware of it or not, already operate under some form of management-implemented policies and procedures, often developed over time and passed on through on-the-job training. A TSMS collates these policies and procedures into an organized, reviewable document, where procedures become uniform and consistent. This provides a company with the ability to review and discuss their procedures internally, uniformly adjust them as necessary, and enables auditors to verify that all vessels and employees within the company follow written protocol. These reviews establish a means to identify weaknesses in those policies and procedures, as well as provide a benchmark for continual improvement.

A company can describe safe work practices and thus lay out specific procedures for its crewmembers and shoreside personnel that will most likely ensure safe operations and proper maintenance procedures and actions.

By establishing policies and procedures, the criteria for all to follow are clear, so personnel know what would be expected, and training can be consistent, measurable, and repeatable. Actions necessary to document the performance of specific tasks can be implemented and verified through audits. This leads to confidence on the part of regulators, charterers, employees, managers, and others that the company and its vessels operate within a safety system and comply with regulatory requirements. This also provides an important tool for managing the operations of a company.

The Coast Guard believes that through the process of pulling together and formalizing a towing company's operating procedures and implementing a process of ensuring that all of its employees follow the established procedures, the risk of harm to people, property, and the environment will be reduced. As proposed in this NPRM, a TSMS would provide instructions and procedures for the safe operation of the vessel, document authorities, detail reporting requirements, establish quality procedures, and establish and document internal and external auditing. The elements that would be required in an acceptable TSMS are included in the proposed regulatory text.

The complexity of the TSMS would be based upon the number of vessels, type of operation, area of operation, and the nature of the risk associated with the towing operations covered by the TSMS. The Coast Guard understands that full compliance with an elaborate TSMS designed for large operations may be impractical for owners or managing operators with small operations. In these cases, the Coast Guard, through a third party, may approve a significantly scaled down TSMS that is tailored to the operation.

Some owners or managing operators already comply with the International Safety Management (ISM) Code due to the nature of their service. The ISM Code is an internationally mandated safety management system for vessels subject to the International Convention for the Safety of Life at Sea, 1974, as amended (SOLAS). The U.S. regulations that implement the ISM Code may be found in 33 CFR part 96. The Coast Guard is proposing to accept compliance with the ISM Code as an equivalent to the TSMS requirements. In many cases, towing vessels that engage in foreign (international) voyages are required to use the ISM Code. As a result, these vessels should not have to use two separate safety management systems, one exclusively for domestic operation and one for foreign voyages at additional cost. The ISM Code can and does work for these vessels, regardless of where they are operating. The Coast Guard believes that the processes and procedures in place for compliance with the ISM Code will ensure that towing vessels comply with proposed Subchapter M, including the elements of the TSMS.

The Coast Guard considered proposing that all towing vessels comply with 33 CFR part 96, Rules for the Safe Operation of Vessels and Safety Management Systems, in lieu of developing the TSMS. However, through consultation with TSAC, it was determined that development of a safety management system specifically for U.S. towing vessels is appropriate. Most U.S. towing vessels operate on inland waters of the U.S. or on coastwise domestic voyages. The proposed TSMS was developed as an integral part of the subchapter and tailored to these U.S. domestic towing vessel operations. The Coast Guard believes that the opportunity to use this tailored system and related procedures is appropriate for this group of vessels. However, the ISM Code requires compliance with mandatory rules and regulations, including relevant national and international regulations, standards, codes, and maritime industry guidelines that are appropriate for towing vessels operating on international voyages. Therefore the Coast Guard believes that companies following the ISM Code will achieve compliance with the proposed Subchapter M without having to implement another safety management system.

Auditing would play an integral part in the proposed TSMS. Audits would ensure that a TSMS functions as designed. A properly designed TSMS, as proposed, would incorporate both internal and external audits to ensure a constantly functioning system that both identifies and corrects problems before they lead to casualties. Companies that comply with the ISM Code should already incorporate both internal and external audits, with the latter performed by recognized classification societies.

The Coast Guard intends to broaden the available pool of auditors to include organizations that meet prescribed standards, which would include professional qualifications, formal training, past experience, and membership in organizations that oversee quality systems, or any combination thereof. Further discussion about third parties is contained below in section IV.D. ''Third Parties.''

The Coast Guard is proposing that third parties be external of the towing organization to be audited to provide independent review. Prospective auditors that are not ''recognized classification societies'' under 46 CFR part 8 would be required to apply to the Coast Guard for approval and be placed on a list of similarly qualified organizations. The list would be made available to towing vessel owners and managing operators.

The Coast Guard has proposed a traditional inspection scheme as one option for towing vessels. This option includes scheduled annual/periodic inspections by Coast Guard marine inspectors. The other option the Coast Guard has proposed is to establish a TSMS regime that would create new and different requirements and procedures. A TSMS would require detailed processes, procedures, recordkeeping, and auditing. It would also provide methods to document compliance with the TSMS, which may include logbooks, non-conformity reports, and/or reports of audits. It is through this documentation that the vessel owner or operator is able to demonstrate compliance.

The Coast Guard is seeking comments on the costs and benefits of the SMS requirement. We are particularly interested in these topics:

(1) Additional compliance options, in addition to the proposed TSMS and Coast Guard inspection regime, that could provide similar benefits at a lower cost;

(2) Flexibilities to the proposed SMS requirements that could provide relief to

small entities while providing similar benefits;

(3) The economic impact on small entities if implementing an SMS became a requirement rather than an option; and

(4) Modifications that could reduce the paperwork and recordkeeping requirements contained in the SMS requirements.

D. Third Parties

The Coast Guard proposes to establish approval procedures for third-party TSMS auditors and surveyors, to carry out routine compliance activities under Coast Guard oversight. The Coast Guard believes that using third parties to carry out compliance activities provides the maximum flexibility in that it reduces vessel downtime, provides greater flexibility in scheduling inspections, and provides greater flexibility in meeting required standards. Using third parties to oversee routine compliance activities would also provide the Coast Guard with more flexibility to apply its resources when and where they are needed most. Third-party auditors would review and approve the TSMS and ensure that it complies with the proposed requirements. Third-party auditors would also conduct required external audits of a TSMS to verify that the system functions as intended. In instances when the regulations require the use of a surveyor, an approved third-party surveyor would be required, providing independent technical expertise to examine the vessel, its systems, and equipment.

Prospective organizations that seek approval as a third party would be required to submit an application to the Coast Guard. Approved third parties would be placed on a publicly-available list maintained by the Coast Guard that would state their qualifications as a surveyor, auditor, or both. Third parties would be subject to rigorous Coast Guard oversight to ensure their reports and other documentation are reliable and the approval would be subject to renewal every 5 years. The Coast Guard would also have the authority to suspend or revoke approval of third-party organizations that do not comply with the proposed standards.

Some companies already employ classification societies. Classification societies have significant expertise with both auditing safety management systems and surveying vessels. The Coast Guard proposes to permit classification societies recognized under 46 CFR part 8 to conduct the audits and surveys required by proposed subchapter M, without further approval.

The Coast Guard also proposes to rely on registered Professional Engineers (P.E.s) to verify compliance with construction and arrangement standards as described in proposed part 144.

The Coast Guard has the authority to rely on third parties in the manner proposed in this NPRM under 46 U.S.C. 3103, which provides authority to the Coast Guard to rely on reports, documents, and records of other persons determined to be reliable, as evidence of compliance with Subtitle II of title 46 of the U.S. Code. In the legislative reports associated with this statute, Congress provided clear guidance on entities they felt could comprise the ''other persons'' mentioned in the statute. These ''other persons'' include surveyors, professional engineering societies, marine chemists, shipyards, the National Cargo Bureau and ''other persons that the Secretary believes may be relied upon to professionally inspect or review a vessel to ensure compliance'' with vessel inspection laws (S. Report 104–160, 1996 U.S.C.C.A.N. 4239, 4269). Title 46 U.S.C. 3308 also provides authority to rely on third-party inspectors by stating that the Secretary shall examine ''or have examined'' vessels subject to inspection. This allows the Coast Guard to use reports and other records as evidence of compliance with vessel inspection requirements.

The Coast Guard has a long history of relying on third parties to perform inspection and survey functions on its behalf. In some cases, these third parties are classification societies that are ''recognized'' by the Coast Guard to carry out certain functions. Authority to permit these recognized classification societies to conduct activities is provided by statute (46 U.S.C. 3316) and regulations (46 CFR part 8). These recognized classification societies are instrumental in conducting vessel inspection activities as part of the Alternate Compliance Program (ACP) (46 CFR part 8, subpart B). Examples where the Coast Guard relies on third parties are when the American Bureau of Shipping (ABS) conducts load line surveys (46 CFR part 42), tonnage measurements (46 CFR part 69), and issues international convention certificates (46 CFR part 8, subpart C).

The Coast Guard's use of third parties has not been confined to recognized classification societies. The Coast Guard uses surveyors and P.E.s by adopting a third-party standard through incorporation by reference, such as the Underwriters Laboratories (UL) standard for fire extinguishers (46 CFR 162.028–5). The Coast Guard also uses surveyors or similar entities as ''accepted organizations'' (46 CFR 28.73) and ''similarly qualified organizations'' (46 CFR 28.76) to conduct examinations of commercial fishing vessels (46 CFR 28.76). Finally, third parties play an important role as ''designated examiners'' who qualify personnel who can operate towing vessels (46 CFR subchapter B). ''Designated examiners'' are not employed by the Coast Guard but are trained or instructed to assess and evaluate candidates for a license or license endorsement on behalf of the Coast Guard.

In each of these cases, incorporating third parties into the inspection process has expedited the process and allowed Coast Guard inspection resources to be reinvested. The Coast Guard expects that the use of third parties proposed in this NPRM would provide the Coast Guard with more flexibility in applying its resources when and where they are needed most.

E. Machinery & Electrical (Proposed Part 143)

While developing 46 CFR part 143, the Coast Guard considered the reports provided by ABSG Consulting and TSAC, discussed in sections III.C. and III.D., respectively, earlier in this preamble. These reports were generated by selecting sample marine casualty cases, identifying their main causes, and summarily grouping them into broad categories based on those causes. The reports also proposed a subchapter outline that highlighted general areas on which to focus. For each area pertaining to machinery and electrical systems, the Coast Guard conducted a more in-depth analysis. This included a detailed review of every casualty used in the ABSG Consulting and TSAC reports. For each casualty, the Coast Guard identified both the specific cause included within the broad report category as well as subsequent and contributory causes. When review of the cases was complete, regulations were developed to prevent or mitigate these causes and patterns, with emphasis placed on high risk causes that take into account both consequence and frequency of occurrence. The casualty reports used to conduct this review are all located in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.''

In most areas, the Coast Guard followed the recommendations in the TSAC report; accepting American Bureau of Shipping (ABS) Rules as the default standard for new towing vessels, and following the TSAC proposed subchapter outline for existing towing vessels. ABS rules provide the towing industry with a comprehensive set of standards appropriate to towing vessels that are widely accepted and already in use by many towing companies.

However, the Coast Guard's in-depth analysis uncovered three areas where the Coast Guard believes additional standards are required for existing towing vessels beyond what is outlined in these reports. These areas are: (1) Propulsion, steering and related controls reliability, (2) electrical installations, and (3) a pilothouse alerter system. This section addresses these three areas only; the remaining requirements from proposed part 143 are straightforward and may be found in the proposed regulatory text.

1. *Propulsion, steering and related controls reliability.* The intent of proposed subpart D of part 143 is to eliminate the possibility of a single equipment failure leaving the operator with no control of the tow. This would be accomplished by requiring these inspected towing vessels to have alternative methods of maintaining propulsion, steering, and related controls. These methods are to be independent, so that failure of one does not affect another.

When developing proposed subpart D of part 143, the Coast Guard also created proposed regulations that address concerns expressed in comments received in response to its December 2004 Notice and Request for Comments, discussed below in section IV.K. ''Discussion of Comments.'' (69 FR 78471). Many commenters supported exemptions for certain vessel types, expressed concern about requiring existing towing vessels to be modified, and supported tying regulations to high risk areas. As noted earlier in section IV.B. ''Applicability'', the Coast Guard is proposing to limit the applicability of these proposed rules and address additional types of towing vessels in a later rulemaking effort. We are also proposing to provide an additional 5-year compliance period for affected tow vessels, and proposing to further limit the bulk of the propulsion and steering reliability requirements to long distance oil and hazardous materials tows that we believe present the highest risk of damage to the environment. Additionally, because the requirements would apply to some existing towing vessels, the Coast Guard proposes to provide an additional compliance period of 5 years after the date a vessel obtains its COI to comply, which will result in a gradual phase-in to full compliance between 7 and 11 years after the date of publication of the final rule. This compliance period is discussed in more detail below in Section IV.G. ''Compliance.''

Requiring alternative, independent methods of maintaining propulsion, steering, and related control is not a new concept for vessels transporting significant amounts of cargo. The Coast Guard requires alternative, independent steering on cargo ships (including oil tankers), with more robust requirements for oil tankers. Cargo ships are also required to have either alternate, independent methods of propulsion or alternate, independent vital auxiliaries critical to propulsion. Additionally, when cargo ships' engine rooms are minimally or periodically unattended—almost universally the case on towing vessels—alternate, independent propulsion and steering control methods are required. Classification societies also require alternative, independent methods of maintaining propulsion, steering, and related control; the ABS rules referred to in proposed § 143.435 are an example of this.

The Coast Guard notes Congressional interest in harmonizing requirements for oil tankers and vessels towing oil and hazardous materials in bulk. The Senate version of the Coast Guard Authorization Act for Fiscal Year 2008 (S. 1892), Section 702(a)(2), states: ''In promulgating regulations for towing vessels under chapter 33 of title 46, United States Code, the Secretary of the Department in which the Coast Guard is operating shall consider the possible application of standards that, as of the date of enactment of this Act, apply to self-propelled tank vessels, and any modifications that may be necessary for application to towing vessels due to ship design, safety, and other relevant factors.'' The proposed rule meets this requirement, by, in part, requiring alternative, independent methods of maintaining propulsion, steering, and related control similar to those required of self-propelled tank vessels.

As mentioned earlier, the Coast Guard considered the casualty data contained in the TSAC and ABSG reports when developing proposed subpart D. In its report, TSAC stated that equipment failures accounted for 31 percent of the medium and high severity incidents and about 45 percent of the low severity incidents. Failures in the propulsion or steering accounted for 30 percent of the medium and high severity incidents involving equipment. This tells us that a significant number of medium and high severity towing vessel incidents—roughly 1 in 10—are due to failures in propulsion, steering, and/or related controls. However, this only gives a partial picture.

When considering the risk posed by a particular type of casualty one has to consider low severity incidents as well, because risk includes not only the consequence of a single type of casualty but also the frequency, *i.e.* how often that type of casualty occurs. For example, TSAC reported that human factors accounted for 54 percent of the medium and high severity incidents and about 40 percent of the low severity incidents. If one only considers medium and high severity incidents, human factors account for 23 percent more towing vessel incidents than equipment failures. If one only considers low severity incidents, equipment failures account for 5 percent more towing vessel incidents than human factors. If one considers all incidents regardless of severity, equipment failures account for 2 percent more incidents than human factors because low consequence incidents occur eight times more often than medium and high severity incidents.

Unfortunately, because the TSAC report did not give statistics on the causes of the low consequence incidents, one is not able to determine from the report the relative percentage of all incidents caused by failures of propulsion, steering, and related controls. However, the ABSG report gives statistics on both high and low consequence incidents. That report categorized roughly 1 percent of towing vessel incidents as high consequence and 99 percent as low consequence and stated that 23 percent of high consequence incidents and 40 percent of low consequence incidents were due to equipment failures. Failures in propulsion, steering, or related controls accounted for 20 percent of the high consequence and 87 percent of the low consequence incidents involving equipment failures. This indicates that roughly 35 percent of all towing vessel incidents are caused by failures of propulsion, steering, or related controls.

When developing proposed subpart D, the Coast Guard considered the impact on industry. A potentially significant impact involves making redundant systems already installed on existing towing vessels ''independent,'' as defined in proposed § 136.110. The Coast Guard notes that a large majority of vessels subject to these regulations are already equipped with redundant systems; the cost to make these redundant systems independent is both reasonable and justified. For example, the Inland River Record, published annually by the Waterways Journal, indicates about 90 percent of inland vessels have two or more propulsion engines and shafts. (A copy of this document has been placed in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.'') The majority of the remaining 10 percent, listed in the Inland River Record as having a single shaft, are vessels not included in the applicability of this NPRM. Currently, vessels with two or more propulsion engines and shafts may have some or all of their fuel, oil, and cooling water piping/pumps or controls (air, mechanical, electrical) common to multiple engines. In order to comply with proposed § 143.410, some vessels may require modification to provide duplicate, independent components to achieve system independence. Other common examples of modifications to make redundant systems independent include separate electronic control circuitry on generators and separate sumps for steering gear hydraulic fluid. As many of the towing vessels currently comply with aspects of the proposed sections, modifications are not expected to require a major overhaul of the vessel. Costs to make modifications are discussed in the separate regulatory assessment for this NPRM, but the Coast Guard proposes to minimize costs by allowing owners and operators up to additional 5 years to bring their vessels into compliance with this requirement, to provide sufficient time to plan for and incorporate these modifications into the vessel's scheduled maintenance period.

2. *Electrical installations.* The Electrical installation requirements are in proposed §§ 143.305 and 143.340–143.360 of subparts B and C of part 143. These sections would require towing vessels to meet specific standards for electrical installations and provide a deferment period for existing towing vessels. The Coast Guard believes that poorly wired and insufficiently maintained electrical systems pose sufficient risk to justify establishing the proposed electrical requirements.

When developing these sections, the Coast Guard consulted the ABSG Consulting and TSAC reports. These reports recommended that electrical installations on existing towing vessels be suitable for the purpose intended and maintained in good operating condition. The Coast Guard agreed with the recommendations and incorporated specific standards dealing with wiring methods, overcurrent protection, electrical connections, grounding, and ground detection into the proposed rule.

The TSAC report stated that 4 percent of high consequence incidents involved electrical failures, but was silent on low consequence incidents. The ABSG report did not have an electrical category. The lack of discussion on electrical incidents in these reports is not unexpected because the reports focused on the primary cause of an incident, not contributory ones.

However, the Coast Guard conducted its own in-depth analysis of the cases reviewed for the ABSG report, along with deficiency reports from examinations of towing vessels during compliance exams, conducted pursuant to 33 CFR part 104 as part of the implementation of the Maritime Transportation Security Act of 2002 (MTSA) (46 U.S.C. chapter 701). These reports provided anecdotal evidence that poor electrical installation and maintenance is a concern on towing vessels. From January 2006 through August 2008, the Coast Guard conducted 768 of these MTSA compliance examinations and issued 2949 deficiencies. Electrical deficiencies involving poor installation and maintenance accounted for 8 percent (226) of the deficiencies. This 8 percent deficiency rate highlights the need to establish more specific standards for electrical installations on towing vessels.

During its in-depth analysis of the ABSG report, the Coast Guard noted several instances where an electrical failure was either the primary cause or a contributory factor even though the report listed some other cause. For example, a significant number of incidents categorized as propulsion, steering, or generator failures were caused by an electrical problem that eliminated the operator's ability to maneuver the tow. Additionally, many cases were attributed to corrosion induced hull failure; however, the improper grounding of electrical systems, which is known to contribute to corrosion induced hull failure, was not investigated.

When developing proposed §§ 143.305 and 143.340–143.360, the Coast Guard sought to create regulations that address concerns noted in comments received on its December 2004 Notice and request for comments, discussed below in Section IV.K. ''Discussion of Comments.'' In response to these comments, the Coast Guard proposes to limit the applicability of §§ 143.340–143.360, opting to cover towing vessels of limited route or service in a later regulation. We also propose providing a longer compliance period for these requirements, providing for a deadline of 5 years from the date of the issuance of the initial Certificate of Inspection. The Coast Guard minimized prescriptive material requirements, such as UL listed cable or circuit breakers, which would require expensive replacements and thus increase the cost to tow vessel owners and operators. The most significant material requirement proposed in §§ 143.340–143.360 is found in proposed § 143.340(a)(3) and (b)(9). It would require two sources of power for certain critical systems typically reliant on electrical power such as navigation equipment, radios, and emergency lighting.

3. *Pilothouse alerter system.* Pilothouse alerter systems detect potential operator incapacitation and alert other crewmembers. A variety of methods are used to detect this, such as a lack of personnel movement or rudder commands for a specified interval. After detection, an alarm sounds in the pilothouse. If it is not acknowledged for a specific interval, another alarm alerts crewmembers in other areas of the vessel.

The pilothouse alerter system requirements are found in proposed § 143.325. The Coast Guard considered the NTSB report of the Robert Y. Love allision with the I–40 Bridge, which killed 14 people and caused more than $60 million in bridge damage. (A copy of this report has been placed in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.'') The report stated that the master became incapacitated by a medical condition 4 minutes before the bridge allision, and listed a pilothouse alerter as an appropriate preventative measure (*See* Report at 63).

The Coast Guard reviewed its data from 1993 to 2003 for related incidents, and uncovered eight incidents where the operator died while navigating the vessel. Other cases also indicated probable incapacitation of the operator. Towing vessels often operate with large tows in congested or confined waterways and near critical infrastructure such as bridges, often with only the operator in the pilothouse. A towing vessel and its tow, out of control because the only operator becomes incapacitated, is capable of doing significant damage to bridges, other vessels, or shoreside facilities; it may also run aground and lose cargo or obstruct the waterway. Even in open water an out-of-control tug risks a grounding or collision. Therefore, the Coast Guard is proposing a requirement for a pilothouse alerter system with the exception that it is not necessary if a second person is provided in the pilothouse.

F. Functional Requirements

The Coast Guard is providing an alternate format in two of the parts included in proposed subchapter M: Lifesaving (proposed part 141) and

Machinery and Electrical (proposed part 143). This format includes the use of functional requirements in appropriate sections. Functional requirements indicate what the section is trying to achieve in the most non-prescriptive manner possible; they provide performance standards stating what to do, and not how to do it. Where appropriate, each regulation section also contains a prescriptive option that does not need to be followed, but following it guarantees compliance with the section. This prescriptive option represents one way to comply with the functional requirements (performance standard) in the section; industry is free to propose alternative methods of compliance to a cognizant Officer in Charge, Marine Inspection (OCMI) or an approved third party. We are specifically seeking comments on whether this format is preferred to the more traditional formats, found in the other parts of proposed subchapter M.

G. Compliance

We are proposing a compliance scheme that we believe would provide adequate time for industry to develop their TSMS, implement it on their vessels, and obtain COIs and spread out the cost of doing so over several years. Owners and managing operators who selected the TSMS option would have 2 years from the effective date of a final rule to create their TSMS, have a third party approve their TSMS, and have a third party issue their TSMS Certificate. They would have 4 years from the date of that TSMS Certificate to bring all vessels under their ownership or management into the TSMS and obtain Certificates of Inspection. We are proposing a requirement that owners and managing operators bring 25 percent of their fleet into compliance in each one of those 4 years, so as to avoid a strain on Coast Guard and third-party resources at year four.

Owners and managing operators of towing vessels subject to Subchapter M requirements would need to select the annual Coast Guard inspection option 2 years from the effective date of a final rule, if they have not created a TSMS by that point. Towing vessels without a TSMS would be subject to the annual Coast Guard inspection regime 2 years from the effective date of the final rule. They would have 4 years from that date to obtain Certificates of Inspection for all vessels under their ownership or management. We are proposing that owners and managing operators bring 25 percent of their fleet into compliance in each one of those 4 years, to avoid straining Coast Guard resources and those of owners and managing operators.

The machinery and electrical requirements discussed above in Section IV.E., ''Machinery and Electrical,'' would have even longer compliance periods. We are proposing to allow for an additional 5-year period after the issuance of the first Certificate of Inspection (COI) to a vessel. This would allow the vessel owners or managing operators who choose the TSMS option to plan for compliance within their TSMS, and to work it into the regular scheduled maintenance periods for the vessel.

H. Part-by-Part Summary

In this section, we briefly outline the several parts that we propose to add as subchapter M. We have not detailed the proposals for each part; instead, we strove to draft regulatory text that is easily understandable. This section highlights the requirements that can be found in each part.

Part 136, ''Certification,'' outlines procedures and requirements for obtaining, amending, and renewing a COI, permits to proceed, and permits to carry an excursion party. Part 136 defines the terms used in the subchapter, and provides a description of vessels that are subject to these regulations. The applicability provisions discussed above in section IV.B. ''Applicability'' may be found in this part.

Part 137, ''Vessel Compliance,'' describes how to come into compliance with the requirements of Subchapter M, including how to conduct, and the frequency of, TSMS surveys and audits, including a summary of the items to be examined. It also outlines alternative methods for carrying out vessel compliance activities. It proposes the contents of required reports and the qualifications required for the various personnel who carry out compliance activities.

Part 138, ''Towing Safety Management System (TSMS),'' proposes requirements for towing vessels subject to inspection that select the TSMS option. Such vessels must be operated in compliance with a safety management system, to be known as the TSMS. This part describes the contents to be required of a TSMS, including management policies and procedures that serve as operational protocol. Also described are procedures related to the approval of a TSMS, internal and external audits of a TSMS, and documentation and oversight. The TSMS provisions discussed above in section IV.C. ''Towing Safety Management Systems (TSMS)'' may be found in this part.

Part 139, ''Third-Party Organizations,'' describes the qualifications and procedures for organizations that audit TSMSs and/or survey vessels. An organization seeking to perform audits and/or surveys would be required to submit an application to the Coast Guard for approval. Approvals would be valid for 5 years with procedures for renewal provided in this part. The Coast Guard would also review relevant information concerning individuals within the organization that would conduct the audits or surveys. Also described in this part are procedures relative to Coast Guard continuing oversight of third-party organizations. This includes procedures for suspension and revocation of approval. The third-party provisions discussed above in section IV.D. ''Third-Party Organizations'' may be found in this part.

Part 140, ''Operations,'' describes health, safety, and operational requirements for vessels and crewmembers serving onboard the vessels. This includes crewmember training and drills. This part would also establish recordkeeping requirements for towing vessels required to comply with subchapter M, requiring the recording of certain drills, training, and operational activities. Navigation and towing safety requirements are also described in this part. To develop this part, the Coast Guard considered the recommendations of the Towing Safety Advisory Committee, reviewed requirements that currently apply to uninspected towing vessels, and reviewed requirements for other types of inspected vessels.

Workplace safety and health requirements onboard uninspected towing vessels are enforced by the Occupational Safety and Health Administration (OSHA) (29 CFR parts 1910 and 1915). However, under a 1983 Memorandum of Understanding (MOU) between the Coast Guard and OSHA, once the Coast Guard prescribes regulations for a class of vessel that is subject to inspection under 46 U.S.C. 3301, OSHA will not enforce its standards against owners and operators of those vessels with respect to the working conditions of seamen. The Coast Guard believes that crewmember safety and health requirements aboard towing vessels should not be lost due to the change in status from uninspected to inspected vessels, and thus proposes safety and health standards that would apply on inspected towing vessels. To develop these standards, the Coast Guard reviewed the OSHA standards and considered adopting them whole cloth. We also considered the recommendations contained in the reports provided by TSAC. The regulations proposed in this NPRM use elements of both. We believe they are appropriate for the nature and service of towing vessels. Workplace safety and health requirements may be found in subpart E of part 140.

Under provisions in §§ 136.170 and 136.203 of this proposed rule, there would be a number of years between the effective date of a final rule in this rulemaking and when a vessel subject to subchapter M would need to obtain a certificate of inspection. Note, however, that once a final rule becomes effective, the requirements in it would be enforced by the Coast Guard. As with these COI provisions, certain part 140 provisions as proposed would provide a period of time before compliance is required. While § 140.500 would provide 3 years after the effective date to implement a health and safety plan, compliance with the regulations on which that plan would be based—*e.g.,* using vessel equipment in accordance with the manufacturer's recommended practice and in a manner that minimizes risk of injury or death, and making appropriate personal protective equipment (PPE) available and on hand for all personnel engaged in an activity that requires the use of PPE—would be required as soon as the rule became effective. Once an inspection of towing vessels final rule became effective, vessels subject to it would become ''inspected vessels'' under the USCG–OSHA MOU, and Coast Guard regulations would apply. Note, however, that OSHA will continue to enforce its requirements on shipyard employers that perform shipyard employment subject to 29 CFR 1915 on inspected and uninspected vessels.

In proposed § 140.655, Prevention of oil and garbage pollution, we state that towing vessels must comply with 33 CFR parts 151, 155, and 156, as applicable. We request comments on whether we should require all towing vessels subject to Subchapter M to track oily waste disposal in the towing vessel's record book or limit recording requirements to existing requirements in 33 CFR parts 151 or 155 and to vessels subject to those parts.

Part 141, ''Lifesaving,'' describes requirements for lifesaving equipment, arrangements, systems, and procedures. Included in this section are readiness and testing requirements for lifesaving equipment on inspected towing vessels as well as minimum lifesaving requirements based on the route of the vessel. To arrive at these proposed standards, we considered the recommendations of the Towing Safety Advisory Committee and reviewed standards that apply to other types of inspected vessels in comparable operating areas and consulted with Coast Guard subject matter experts; and are proposing additional requirements that would provide lifesaving protections similar to other classes of inspected vessels.

Part 142, ''Fire Protection,'' describes the requirements for fire suppression and detection equipment and arrangements. This part would establish requirements for portable and fixed fire extinguishing equipment, and related inspection and testing requirements. It also proposes crewmember training and drills with the required fire protection equipment. The fire protection standards proposed in this part substantially retain fire protection regulations that currently apply to most towing vessels and are contained in Title 46 CFR Parts 25 and 27. To arrive at these proposed standards we considered the recommendations of the Towing Safety Advisory Committee, reviewed subchapters for other classes of inspected vessel, and consulted Coast Guard subject matter experts. In a separate rulemaking, entitled ''Carbon Dioxide Fire Suppression Systems on Commercial Vessels'' (RIN 1625–AB44), the Coast Guard has proposed new fire suppression standards for commercial vessels in general. *See* 75 FR 8432, February 24, 2010. In § 142.235 of this Towing Vessels NPRM, which deals with fixed fire-extinguishing systems, we make reference to requirements in 46 CFR subpart 76.15. Please note that the Carbon Dioxide Fire Suppression NPRM proposes to revise subpart 76.15. *See* 75 FR 8443. Also, please note that the Carbon Dioxide Fire Suppression NPRM would revise the definition of ''fixed fire-extinguishing system'' in 46 CFR 27.101. *See* 75 FR at 8438.

Part 143, ''Machinery and Electrical Systems and Equipment,'' describes requirements for the design, installation, and operation of primary and auxiliary machinery and electrical systems and equipment on certain towing vessels. The machinery and electrical provisions discussed previously in section IV.E. ''Machinery & Electrical'' may be found in this part.

Part 144, ''Construction and Arrangement,'' describes the requirements for design, construction, and arrangement of towing vessels which would be inspected under subchapter M, including plan review and approval. The procedures for plan review are proposed, as are qualifications for persons conducting plan review. The part describes different requirements for existing towing vessels and new towing vessels and provides descriptions of requirements for subdivision and stability, visibility, and vessel arrangements related to crew safety such as rails, guards, and escapes. To arrive at these proposed standards, we considered the recommendations of the Towing Safety Advisory Committee, reviewed other subchapters, consulted with Coast Guard subject matter experts and reviewed current Coast Guard processes and procedures relative to vessel construction and arrangement; and are proposing requirements that are similar to other classes of inspected vessels.

I. User Fees

Under 46 U.S.C. 2110, the Coast Guard is required to charge vessel inspection user fees. The regulations contained in 46 CFR 2.10 prescribe procedures and fees for vessels required to have a Certificate of Inspection (COI). We intend to establish a user fee, as required by law, for those vessels required to comply with subchapter M; however we have not included a proposed fee in this NPRM. Once we have received comments on our proposal, and are closer to issuing a final rule, we will propose a user fee through an appropriate analysis of Coast Guard activities related to certification of towing vessels. The Coast Guard will not inspect towing vessels or issue COIs to towing vessels until user fees are established.

Currently, ''sea-going towing vessel'' is defined in 46 CFR part 2 as a ''* * * sea-going commercial vessel engaged in or intending to engage in the service of pulling, pushing or hauling alongside * * *''. However, only towing vessels over 300 gross tons operating beyond the boundary line are currently subject to inspection, and consequently these are the only towing vessels subject to user fees. Without a change to the definition in part 2, smaller towing vessels operating beyond the boundary line would also be subject to inspection and the corresponding user fee, whereas smaller towing vessels not operating beyond the boundary line would not be subject to the user fee.

In order to ensure that only those towing vessels that currently pay a user fee will need to continue to do so, the Coast Guard is proposing to revise the definition for ''sea-going towing vessel'' in part 2, to clarify user fee applicability for certain seagoing towing vessels. The Coast Guard proposes to revise the existing definition by adding the words ''issued a certificate of inspection under the provisions of subchapter I of this chapter'' to the end of the existing definition.

J. Manning

The Coast Guard is proposing to amend the regulations contained in 46 CFR subchapter B to clarify the regulatory requirements for manning of inspected towing vessels. Part 15 of subchapter B contains separate subparts for inspected and uninspected vessels.

With this amendment, we are copying current requirements for uninspected towing vessels, contained in subpart E (Manning Requirements; Uninspected Vessels), into subpart D (Manning Requirements; Inspected Vessels). This ensures that the current qualification requirements for mariners serving aboard towing vessels continue to apply.

Manning requirements for uninspected towing vessels must remain in subpart E because certain towing vessels will remain uninspected vessels for the near future.

K. Discussion of Comments

As stated above in section III.B. ''Regulatory History,'' on December 30, 2004, the Coast Guard published a ''Notice; request for comments, and notice of public meetings.'' (69 FR 78471). The notice asked seven specific questions, which are replicated below, along with a summary of the comments we received on each.

Most of the commenters were generally agreeable to creating new regulations and a safety management system for towing vessels. While some promoted either regulations or a safety management system, others called for a balance between the two items. Several commenters criticized the creation of new regulations and a safety management system, stating that vessels are already subject to regulations and citing the superior safety record of the towing industry as a whole.

The Coast Guard received a large number of comments from industry representatives who are members of the American Waterways Operators (AWO). Many AWO members' comments were similar to one another. Additionally, comments were received from organizations that represent environmental groups, mariners, passenger vessel organizations, former Coast Guard members, government entities and officials, and other sectors of the industry. Some of these comments supported AWO's positions, while others completely disagreed. Overall, many commenters said the towing industry was unique, and some discussed unique ways to regulate the industry.

Question One: Towing vessels of a certain size (300 or more gross tons) are already inspected vessels and are subject to a variety of existing requirements. Should the Coast Guard use any of these existing standards (or standards for other types of inspected vessels) for incorporation into the new regulations regarding the inspection of towing vessels? If so, which regulations or standards should be incorporated into these new regulations?

A majority of the responses indicated the Coast Guard should not use existing standards when developing the regulations for towing vessel inspections. The commenters stated the towing industry is ''unique'' and fills a variety of functions from assistance towing to towing certain dangerous cargos. Additionally, towing vessels work in a variety of locations, such as inland waterways and coastal areas, and come in a large assortment of shapes and sizes. Instead of the traditional regulations, many of these commenters suggested using a safety management system.

Commenters noted that safety management systems are flexible in nature and allow the industry members to tailor programs to their specific needs based on real-time operations, risk analysis, and casualty statistics. They indicated that focusing on a safety management system may allow deviation from ''prescriptive'' standards and create a system that is ''reasonable, effective, and necessary * * *''.

However, other commenters expressed openness to using existing standards when creating the new regulations. Commenters who argued in favor of using existing standards said there were some existing standards that could easily be applied to the towing industry. A few of these commenters stated that the House of Representatives Conference Report to the CGMTA 2004 (''House Report'') mandated the use of existing standards. We were unable to substantiate the claim that the House Report on the CGMTA 2004 mandated the use of existing standards. Furthermore, commenters declared that while a safety management system is the best way to ensure that all segments of the industry are covered, it is not intended to take the place of traditional inspections and regulations.

Some of the existing regulations cited were those outlined in the Gulf Coast Mariners' Association's Report R–276, Revision 8. This report can be found in the docket for the request for comments [USCG–2004–19977] as item 14; to access this report, use the procedures listed in section I.B. ''Viewing comments and documents.'' Commenters also listed several subchapters of Title 46 as potential sources for the tow vessel regulations, including subchapters C, D, F, H, I, J, K, L, and T.

The Coast Guard carefully considered input received in response to Question One and has decided to both use existing standards/regulations and to develop new towing vessel-specific standards and regulations. For example, we adopted all of the existing fire-suppression requirements from 46 CFR part 27 into part 142 of these proposed regulations. Inclusion of these existing regulations is also supported by TSAC. An example of a towing-specific standard is the creation of the TSMS option and its use throughout these proposed regulations. This requirement and the regulations pertaining to it, which can be found in proposed part 138, were created exclusively for this rulemaking, based on the comments the Coast Guard received from our Notice (and is also supported by TSAC).

Question Two: Title 46, United States Code, specifies the items covered with regard to inspected vessels including lifesaving, firefighting, hull, propulsion equipment, machinery, and vessel equipment. However, the legislation that added towing vessels to the list of inspected vessels, authorized that the Coast Guard may prescribe different standards for towing vessels than for other types of inspected vessels. What, if any, different standards should be considered with regard to inspected towing vessel requirements from other inspected vessels?

Most responses treated Question Two as part of, or an extension of, Question One. Some commenters answered the questions together; others gave very similar answers to both questions. Where possible, we separated the commenters' answers to best reflect their statements and avoid repetition of the issues.

Beyond the subchapters mentioned in the previous question, some commenters suggested the standards covering manning and the particular subchapters applicable to the barges being towed were important. Some commenters disagreed and stated since towing vessels do not actually carry cargo (or passengers), they should not follow the standards applicable to the barge. One commenter suggested a new ''classification system'' should be created to cover the wide variety of towing vessels in operation.

Title 33 CFR part 96 was cited as containing standards that could be applicable to towing vessels. This part contains the standards for safety management systems for other types of vessels and could be used as a model for safety management systems for towing vessels. Some specific sections cited were §§ 96.100 through 96.250, and creating ''new §§ 96.225, 96.235, 96.245, and 96.255.''

Many commenters called for new and unique regulations and a safety management system. Several commenters said that a safety management system should be based on risk and casualty data, rather than on existing regulations. A couple of commenters cautioned not to rely strictly on accident data because some accidents and ''near-misses'' may not be reported. The main concern expressed by many commenters was that a safety management system should be easy to implement for both large and small companies alike.

Other systems, such as the TSAC–Industry Working Group's ''straw man,'' AWO's Responsible Carriers Program (RCP), American Bureau of Shipping (ABS) standards, the oil companies' Ship Inspection Report (SIR and SIRE) Programs, the Streamline Inspection Program, and the 8th Coast Guard District boarding form were discussed as models for a safety management system. The TSAC ''straw man'' document, available in the docket for the request for comments [USCG–2004–19977] as item 32 (to access this document, use the procedures listed in section I.B. ''Viewing comments and documents.'') was cited most frequently, with the AWO's RCP and International Safety Management (ISM) close behind. A few commenters said several different systems could be combined to fill in any gaps that may exist.

After carefully considering the comments received for Question Two, the Coast Guard decided not to just rely on standards or regulations found in other, existing vessel inspection subchapters. The Coast Guard decided that the unique nature of the towing industry and towing operations warranted the development of some new standards and regulations that would pertain exclusively to towing vessels. In addition to the TSMS cited in our discussion in Question One, the Coast Guard also proposes other towing vessel-specific provisions including expansion of the use of third-party organizations as part of the Coast Guard's proposed TSMS-based towing vessel inspection for certification regime. Third-party organization requirements are found in proposed part 139. Expanding the use of third-party organizations would provide greater flexibility to owners and managing operators of inspected towing vessels that choose the TSMS option to schedule various vessel-related activities and meet the Coast Guard's proposed requirements.

Question Three: Towing vessels vary widely in terms of size, horsepower, areas of operation, and type of operation. Under what circumstances, if any, should a towing vessel be exempt from the requirements as an inspected vessel?

Some commenters believed exemptions should be given to vessels under 26 feet (8 meters), assistance towing vessels, and towing vessels used in fleeting and construction sites.

Several commenters suggested that some older vessels should be exempt because they are difficult and expensive to retrofit in order to comply with new regulations. Some of the specific categories of older vessels mentioned for exemption were towing vessels less than 65 feet, vessels with less than 759 horsepower, vessels less than 100 gross tons, and those operating within sight of land. One commenter suggested exemptions for towing vessels over 300 tons because they are already subjected to regulation. Some commenters suggested exemptions for towing vessels that tow or push passenger barges. Some of these commenters said these towing vessels often received ''courtesy'' inspections when the barges they tow or push were inspected. Therefore, it was unnecessary to subject passenger barge towing vessels to another complete inspection.

A few commenters said there should be no exemptions. These commenters said mariners and the environment would be better protected if every towing vessel complied with the new regulations. Some commenters said the regulations could be a minimum foundation for all towing vessels, and a safety management system could cover the specifics for unique segments of the industry.

Some commenters did not agree that fleeting towing vessels should be exempt because they have a questionable safety history and must maneuver in small spaces. Several commenters recommended exemptions for ''day shift'' vessels which only carry crewmembers during the day and have no sleeping quarters.

A few commenters said there was no reason for any towing vessel to be completely exempted from inspection regulations. However, they said there was a possibility of making different regulations to cover different types of towing vessels and making portions of the regulations apply to some vessels but not to others. Another commenter said that the 8-meter cut-off should not apply because ''this only encourages one to use a boat too small for the job and penalizes competition of one with a larger vessel that is using prudent seamanship.''

Some commenters suggested that exemptions should be handled on a case-by-case basis. These exemptions could be handled by the Captain of the Port (COTP) directly, or the requests could go to Coast Guard Headquarters, with decisions made by the Commandant.

Other commenters said exemptions could be made based on a towing vessel's area of operation. Vessels operating in ''low risk'' areas could have different regulations than those operating in ''high risk'' areas.

During the course of our interactions with TSAC, it was clear that we could not categorically exempt a subset of the towing vessel population for reasons of vessel size or service. However, the Coast Guard determined that it should not propose regulations that would establish uniform requirements for all towing vessels regardless of size or service. We evaluated regulatory requirements and applied them to particular types or service, based on risk. For example, we adopted the existing requirement to provide an exception from certain fire-suppression requirements for towing vessels engaged in certain services such as harbor-assist towing or vessels operating in a limited geographic area. These exceptions from certain fire-suppression requirements are found in proposed part 142. Furthermore, while the towing vessels identified in proposed § 136.105 have been exempted from this NPRM, the Coast Guard intends to propose regulations for these vessels in a future rulemaking.

Question Four: Should existing towing vessels be given time to implement requirements, be ''grandfathered'' altogether from them, or should this practice vary from requirement to requirement?

The commenters indicated the regulations should not be implemented immediately; however, the suggestions for the length of time for compliance varied widely. A majority of commenters supported some level of ''grandfathering,'' but for the most part, applied ''grandfathering'' only to equipment requirements.

Most commenters stated that implementation should begin between 180 days (6 months) and 1 year after publication of the final rule. A few commenters suggested that the implementation should start ''without delay,'' while others proposed a sliding scale or a flexible schedule, depending on the requirements. One commenter said that the Coast Guard should have the responsibility of deciding the implementation period. Some commenters said that there should be adequate time for mariners to participate in both the rulemaking and the implementation. One commenter focused on the safety management system, saying that safety management systems should have a 1-year phase-in period. According to AWO members, 6 months to 1 year would be sufficient time to implement the RCP and train new people on using an already established safety management system.

''Grandfathering'' was a highly important issue in many of the comments. Some commenters said ''grandfathering'' should only be for vessels that would be too difficult and too expensive to modify. One commenter said ''grandfathering'' can ''be employed to ensure that operators of existing towing vessels can phase-in new requirements in a cost-effective manner. Some requirements should be permanently grandfathered where the requirement necessitates major reconstruction. * * *''

Other commenters said it was not clear that the House Conference Report to the CGMTA 2004 allowed ''grandfathering'' of any kind. Some commenters suggested offering waivers for those vessels unable to comply with new structural requirements. It was suggested that such waivers and limitations could be reflected on the COI.

Most commenters stated there should be no ''grandfathering'' from the implementation date of a flexible safety management system. Other commenters said that with a flexible safety management system, there may be a need for some minor ''grandfathering,'' but it should predominately be avoided. One commenter said that allowing extensive ''grandfathering'' would have ''the unintended consequence of potentially stifling new construction.''

Some commenters suggested that all existing towing vessels be ''grandfathered'' into the new regulations. Other commenters limited this to towing vessels already operating under a safety management system. Other commenters said that vessels already operating under ISM are class inspected; therefore, adding another Coast Guard inspection would be redundant. One commenter suggested a complete phase-out of existing towing vessels so that only new towing vessels would be following the new regulations.

We have determined that the complete ''grandfathering'' of existing towing vessels, as that term is commonly understood, is not appropriate under the mandate provided in the CGMTA 2004 because grandfathering all existing towing vessels from all aspects of these proposed regulations would not improve safety within the towing industry and could have the undesired effect of influencing towing vessel owners to retain existing, unsafe vessels instead of building or purchasing new vessels. With regard to the question of giving vessels additional time to comply with certain provisions of these proposed regulations, we carefully considered the comments received and are proposing to give towing vessels that would need to comply with subchapter M additional time to comply with certain proposed requirements. For example, specific requirements that were deferred for existing towing vessels are included in Part 143, Subparts C and D. We feel that the additional time to comply with these requirements will not only provide more time for vessel owners and operators to complete the necessary work, but it will also allow for a longer period to budget expenses necessary to complete the required work.

Question Five: Should existing towing vessels be treated differently from towing vessels yet to be built?

Several commenters addressed Question Five much like Question Four. Some respondents chose not to answer Question Five, stating that Question Four covered what they wished to express. Others gave a ''yes'' or ''no'' answer and referred to their comments in Question Four. One commenter stated ''[a]ll new construction should meet an established set of inspection standards. * * *'' Another commenter said that other inspection regimes have ''grandfathering'' so the same should apply to towing vessels. Furthermore, this same commenter stated that the Coast Guard can add new requirements for existing towing vessels.

We received several comments concerning mariner safety on both new and existing towing vessels. One commenter said that treatment should differ according to the vessel's age because old vessels are generally not as safe as new ones. The commenter said existing towing vessels would be too difficult and expensive to retrofit to meet the new standards. Other commenters said it made sense to treat new and existing towing vessels differently because the existing towing vessels were built to meet certain needs and regulations in force at the time of build. However, these vessels may not comply with new regulations.

Many commenters said that both new and existing towing vessels should be able to follow a safety management system. These commenters favored incremental and flexible change that would allow them to continue operating their towing vessels as they exist, while making them safer. Other commenters referenced the House Conference Report to the CGMTA 2004, saying that there was no indication that there should be different treatment between new and existing towing vessels. These commenters said making such a distinction would imply a ''traditional inspection regime'' rather than a safety management system. Another commenter stated different treatment would only be acceptable if existing towing vessels showed and demonstrated an intent to meet the new regulations.

One commenter said that a safety management system should be implemented for newly constructed vessels as soon as possible, while existing towing vessels should have phase-ins for required physical changes, corrections, and upgrades. Another commenter stated that existing towing vessels should either become compliant within a certain amount of time or be completely phased-out. Furthermore, this commenter said new and existing towing vessels that are not phased-out should implement a TSMS within 6 months of the final regulations. Similarly with Question Four, some commenters suggested exceptions with respect to design, construction, technology, and equipment standards.

A commenter from a governmental agency said the new regulations should be risk-based rather than whether the towing vessel is new or existing. Additionally, the commenter said the type of vessel and area of operation, as well as the condition of the vessel, should determine safety standards. Finally, the commenter stated that the operational risk assessment will determine how quickly to implement the new regulations.

After carefully considering the comments concerning the treatment of existing towing vessels and towing vessels yet to be built, the Coast Guard is proposing additional requirements for inspected towing vessels yet to be built that will not apply to existing towing vessels. This concept is particularly exemplified in both proposed Parts 143 and 144 where requirements for existing towing vessels are dealt with in one subpart and requirements for new vessels are dealt with in a separate subpart. The Coast Guard recognizes that existing towing vessels have been in service for extended periods of time, in some cases decades, which indicates that some systems or components adequately withstood the test of time.

The proposed inspection regimes, which include the use of a TSMS and third-party compliance surveys or a Coast Guard inspection regime, will ensure that these systems remain safe. At the same time, the Coast Guard recognizes that inspected towing vessels yet to be built need to incorporate advances in good marine practice in their design and construction to improve safety of the towing industry.

Question Six: The same act that requires inspection of towing vessels authorizes the Coast Guard to develop a safety management system appropriate for the towing vessels. If such a system is developed, should its use be required for all inspected towing vessels?

Several commenters answered this question, ''Yes'' with no further qualifications. Most commenters supported developing a safety management system, though some suggested exemptions for the types of vessels mentioned in comments to Question Three. Commenters recommended a safety management system because it is flexible and fits both large and small companies, as well as differing geographic areas and types of operation. Additionally, commenters noted that a safety management system provides an alternative from traditional inspection regimes because ''previous inspection modality * * * would not be appropriate for our industry or be supported by data in a preferred risk-based system.''

A few commenters did not fully endorse a safety management system program. One said a safety management system could ''kill many small towing vessel companies.'' Furthermore, the commenter stated that a safety management system should be voluntary, but being voluntary could be harmful to mariners. To prevent such harms, a ''small business outreach'' program, in conjunction with a safety management system program, should be developed.

Another commenter opposed safety management systems since companies wishing to participate in a safety management system could follow 33 CFR part 96 ''Rules for the Safe Operation of Vessels and Safety Management Systems.'' Other commenters suggested using already established programs when creating a safety management system rather than developing a new program. Some commenters expressed concern that safety management systems were too flexible; giving companies a way around making their vessels safer. One commenter said regulations, rather than a safety management system, are the best way to move forward. Several commenters favored no new action because towing vessels ''have been running efficiently for more than a century and there are no problems that need to be addressed.''

Another commenter argued against requiring safety management systems because of the possible increase in paperwork. Several commenters expressed a concern about additional paperwork because there are not enough man-hours for responsible crewmembers to complete it. One commenter suggested records should be kept by a designated company officer, and those records should remain in the company's land-based office.

Several commenters said a safety management system will be helpful, but it would still leave gaps requiring regulatory solutions. One of these commenters said ''suitable regulations'' should be developed first to govern the industry. A few commenters referred to the CGMTA 2004 and the House Conference Report to the CGMTA 2004, stating that a safety management system should not be a substitute for an inspection regime, but rather a supplemental way to ensure towing vessels are compliant with their Certificate of Inspection.

For the reasons discussed earlier in Section IV.C., including Congressional authorization for a safety management system, a statutory directive to issue an NPRM based on that authority, and recommendations by TSAC and the NTSB, the Coast Guard proposes an inspection option that utilizes a TSMS but also provides for a traditional, annual inspection regime. Requirements for the TSMS are found in proposed part 138.

Question Seven: Examples of existing safety management systems include the International Safety Management (ISM) code and the American Waterways Operators Responsible Carrier Program. If a safety management system is used, what elements should be included in such a system?

Most of the elements discussed in the comments came from the TSAC-Industry Working Group's ''straw man'' document. Many commenters stated the ''straw man'' provided a model safety management system. However, several commenters suggested the following new elements:

1. Incident, Accident, and Non-Conformity Reporting;
2. Investigation and Corrective Action Policies and Procedures, including Documentation;
3. Vessel and Equipment Maintenance, and Use Policies and Procedures;
4. Manning, Watchstanding, and Training;
5. Person Overboard Recovery Equipment;
6. Designated Person, Master's Responsibility, and Authority; and
7. External Audit and Certification.

Several commenters strongly stated it is not enough to implement equipment requirements, but new regulations must be developed to ensure equipment is in ''operating condition.'' Other commenters gave extensive lists of equipment and manning procedures to be included in the regulations and a safety management system. Another commenter suggested ''True vessel horsepower must be determined and a horsepower to tonnage barge ratio developed.'' One commenter suggested that the lifesaving equipment aboard towing vessels should be similar to the equipment on Coast Guard vessels.

In addition to, and in some cases in place of, using the ''strawman,'' several commenters suggested using current safety management systems as models for creating a new safety management system. These models include the RCP, the ISM Code, Title 33 CFR part 96, Title 46 CFR, the SIRE, the SIP, and the ''Accredited for Commercial Assistance and Professional Towing'' (ACAPT) program for assistance towing vessels if they are included in this rulemaking. Some commenters said regardless of the model proposed, the Coast Guard should develop guidelines to ensure consistent enforcement by all Captains of the Port (COTPs). Other commenters said towing vessel companies should choose one model. A few commenters suggested allowing entities to apply to the Coast Guard for approval of their specific safety management systems.

One commenter said accident data should be used to determine the areas where regulations are needed the most. Such data and risk assessment would show which elements are needed in a safety management system.

The Coast Guard carefully considered the comments received pertaining to the nature and content of a safety management system that might be included in these proposed regulations. The Coast Guard is proposing to require that all inspected towing vessels use a TSMS and the requirements are found in proposed part 138, or equivalent, or be subject to an annual, Coast Guard inspection regime. As discussed above, Congress provided the Coast Guard with authority to establish a safety management system appropriate for towing vessels and has directed that we issue an NPRM based on that authority. Compliance with a company implemented Safety Management

System is the cornerstone of the Towing Safety Advisory Committee's recommendation, and the National Transportation Safety Board has recommended the establishment of a safety management system for towing vessels. Additional discussion on safety management systems may be found in Section IV.C. Requirements for the TSMS are found in proposed part 138.

Additional Comments

We received many comments that covered topics not addressed in the seven questions noted above. One of the subjects covered most was the issue of manning. Several comments from mariners and mariner associations noted manning issues. Some commenters stressed the need to protect the safety of mariners aboard towing vessels. These commenters opined that manning issues had been neglected and this new regulation afforded a chance to fix long-standing problems.

The commenters identified the duty of the deck officer and keeping an appropriate watch as major issues. Some commenters stated there were not enough crewmembers aboard towing vessels to fulfill all the duties in the time available. One commenter said manning, watchstanding, and crew meetings should be required, but there should not be additional ''meetings, drills, maintenance or duties placed on the overburdened system without safe and comprehensive manning requirements.'' One commenter suggested that the proper amount of manning should be determined by the usage of the vessel.

Other commenters were concerned with work hours. Several commenters said captains often complete a 12-hour shift on one vessel, then immediately work another 12-hour shift on different vessel. This practice provides them with very little sleep. The commenters suggested a mandatory rest period for all captains. Another commenter said administrative duties performed by captains and mates should count as work hours because this time may be under-reported.

Some commenters said a labor shortage for inland towing vessels caused work hour problems. These commenters suggested the labor shortage was a result of harsh working conditions with few benefits. One commenter said ''blue water'' operations (*i.e.,* tow vessels operating in an ocean environment) do not have the same labor shortage because the vessels are considered safer to work on. The commenter added that inland towing vessels should have equal standards to these ''blue water'' vessels.

A few commenters said that manning should be equivalent to other types of inspected vessels of similar size and horsepower. Some commenters expressed concern that company managers order captains to take a vessel out, regardless of safety concerns. These commenters said the captain and pilot should have final say on whether a vessel is safe to get underway without repercussions from management.

Some commenters discussed enforcement of manning regulations and licensing of merchant mariners. One commenter said it is unclear how the Coast Guard intends to enforce manning regulations and safety management systems. The commenter said the manning proposal ''criteria'' is vague with no indication of how the criteria will be enforced. Another commenter said there are currently regulations that allow vessels to get underway without the appropriate number of licensed mariners, if it is deemed safe by the master. The commenter believed the Coast Guard should not allow this exception for towing vessels. Another commenter said there was no indication that merchant mariner documents will be included in this rulemaking, and that the Coast Guard should take action on this issue.

As noted above in Section IV.J. ''Manning,'' we are not proposing to change any of the current manning levels required for towing vessels. However, portions of the TSMS covering operations should address many of the concerns raised by these commenters.

In addition to manning, auditing and inspections were topics mentioned frequently by commenters. Some commenters said inspections and safety management system approvals should be done by third-party auditors. Other commenters suggested a combination of third-party auditors and Coast Guard auditors. Yet other commenters said only the Coast Guard should handle inspections and safety management system approvals. One commenter said ''Any safety auditor * * * should be required to meet the highest industry certification to ensure that they are competent to conduct these safety audits.'' Another commenter agreed saying audit companies should be held accountable; as such a system would reduce the inspection burden on the Coast Guard. A commenter stated third-party auditors must not be associated with the companies they are auditing, and should be monitored closely by the Coast Guard. One commenter stated it was important for companies to submit their individual safety management system plans for approval and allow audits by third parties to insure compliance with the plans. The Coast Guard took these comments into consideration while developing the proposed regulations covering the use and approval of third parties.

The Coast Guard is proposing that all inspected towing vessels be operated in accordance with a company-implemented safety management system or be subject to an annual, Coast Guard inspection regime. This rulemaking also proposes contents and procedures relative to safety management systems, and proposes standards and procedures for approval of third parties and the roles and responsibilities of third parties. Additional discussion of safety management systems is provided in section IV.C above; discussion of third-party organizations is provided in section IV.D above. Many commenters discussed the frequency of audits and inspections. These varied from every year to every 3 years to every 5 years. One commenter said the initial inspection date should be based on the anniversary of existing towing vessels, divisible by 5 years. Furthermore, the commenter said every new vessel should be inspected prior to placement in service. Another commenter suggested companies with better safety histories could be inspected less often than those with poor histories.

Some commenters addressed drydocking specifically, saying towing vessels rarely go more than 1 year between drydockings, and the Coast Guard should not need to be present at every instance, although there was some allowance for the Coast Guard to be present at initial drydockings. The Coast Guard took these comments into consideration while developing the proposed regulations covering inspection, audits, and surveys.

Several commenters expressed concern about the level of sophistication of mariners in trying to comply with the new regulations. The commenters suggested creating new regulations that are easy to follow. Other commenters said the regulations should be easy to read for operators and marine surveyors. One of the commenters said the written regulations should be placed onboard towing vessels so that mariners have access to them. Furthermore, the mariners should also have access to ''boarding check sheets for equipment.'' A few commenters suggested offering testing on the new regulations for licensing to ensure mariners understand the changes. Another commenter said the OCMI should assist mariners with questions and comments.

Many commenters requested one location for the new regulation so they are easy to find and follow. One commenter said we should reduce overlapping regulations and clarify ''confusing and incomprehensible tables.'' Another commenter suggested individual updates to 46 CFR subchapters A, E, F, and J, and use of subchapters C, I, S, and W instead of one central location. The commenter also suggested making a new subchapter ''X'' for applicable cross-references to applicable requirements in other subchapters. The Coast Guard considered these comments and developed straightforward, easily understandable regulations, mostly contained in the newly proposed subchapter M.

Other commenters strongly requested the Coast Guard work in a close partnership with TSAC. At several of the public meetings, many of the participants invited the Coast Guard to contact them for further information. Other commenters suggested the Coast Guard should keep mariners involved with the rulemaking. A few commenters discussed placing restrictions on the Certificate of Inspection for vessels towing dangerous cargo barges, or those unable to meet the new regulations. As already noted, the Coast Guard worked extensively with TSAC while developing this NPRM, which included input from nearly 200 individuals.

One commenter discussed penalties for non-compliance, saying companies should be held accountable for not following their safety management systems. Another commenter said the Coast Guard should have the authority to enforce any recommendations that come out of accident reports. A third commenter said, ''the safety regulations for our industry have to target corrective actions that will improve and address human factors * * * like voyage planning, situational awareness, [and] crew endurance.'' One commenter said mariners should have access to the Marine Safety Office (now Sectors) to report hazards, and have an inspector address every complaint. Again, these comments were considered in the development of this NPRM. We invite the public to suggest additional topics or changes to the proposed regulation in their comments on the NPRM, as noted in section I. ''Public Participation and Request for Comments.''

L. Hours of Service and Crew Endurance Management Programs

As we stated in our discussion of statutory authority, in Section III.A of this preamble, 46 U.S.C. 8904(c) authorizes the Secretary to establish maximum hours of service regulations for individuals engaged on a towing vessel that is at least 26 feet in length. The legislative history for 46 U.S.C. 8904(c) makes clear that this provision gives the Coast Guard authority to establish ''scientifically based hours-of-service regulations that set limits on hours of service, provide predictable work and rest schedules, and consider circadian rhythms and human sleep and rest requirements'' as recommended by the National Transportation Safety Board in 1999, Recommendation M–99–1. See H.R. Conf. Rep. 108–617, 2004 U.S.C.C.A.N. 936, 951.

The Coast Guard is considering establishing hours of service standards and requirements for managing crew endurance, the ability for a crewmember to maintain performance within safety limits while enduring job-related physiological and psychological challenges. The Coast Guard is seeking additional public comment on possible hours of service and crew endurance management program standards and requirements at this time. After considering this additional information, the Coast Guard would later request public comment on specific hours of service or crew endurance management regulatory text if it seeks to implement such requirements.

Specifically, the Coast Guard, in this section IV.L., discusses its views on potential hours of service and crew endurance management program standards and requirements, and seeks addition data and other information related to these provisions. In particular, the Coast Guard seeks additional data and information specifically related to hours of service and performance of work on towing vessels. Although the Coast Guard welcomes all public comments related to these potential requirements, the Coast Guard specifically invites comments on the research discussed below, and responses to the following questions:

- What would be the best way to manage work and rest schedules to ensure sufficient time off for mariners' on towing vessels?
- How many hours of uninterrupted sleep per day do mariners on towing vessels require?
- What would be the best method to ensure that sufficient qualified personnel are available for 12 hours of work per day on a towing vessel?
- What do you view as the potential economic consequences resulting from a mandate that mariners on towing vessels obtain a required number of hours of uninterrupted sleep, such as 7–8 hours, for your vessel or organization?
- What would be the benefits to implementing a mandate that mariners on towing vessels obtain a required number of hours of uninterrupted sleep, such as 7–8 hours, for your vessel or organization? Would such a mandate be effective in reducing vessel casualties and other accidents?
- Despite medical and scientific evidence, discussed below, that most people need at least 7 hours of uninterrupted sleep to restore their cognitive abilities necessary to maintain situational awareness, it is common for watch and rest schedules on towing vessels to fail to permit this minimum amount of uninterrupted sleep. Why have market forces not caused the towing vessel industry to adopt work schedules that permit the minimum amount of uninterrupted sleep necessary for most persons to maintain situational awareness?
- Would a mandate that mariners on towing vessels obtain a required number of hours of uninterrupted sleep, such as 7–8 hours, require a change in watch schedules? If so, what watch schedules would a towing vessel use?
- Would a mandate that mariners on towing vessels obtain a required number of hours of uninterrupted sleep, such as 7–8 hours, require more than changes in watch schedules?
- If your vessel has already changed from a schedule that allows a certain number of hours of uninterrupted sleep, for example 7–8 hours, to a square watch schedule (alternating 6 hours on watch, 6 hours off, 6 hours on watch, 6 hours off, every 24 hours), what factors led to the switch? What factors prevent a towing vessel from having a watch schedule that allows for a certain number of hours of uninterrupted sleep?
- What are the differences in operating costs and workplace injuries based on watch schedules that require a certain number of hours of uninterrupted sleep?
- Would implementing a requirement to provide sufficient time off for mariners on towing vessels to obtain a certain number of hours of uninterrupted sleep, such as 7–8 hours, reduce the rate of injuries and accidents? If you know of relevant injury/accident data to support your comments, we request that you identify or provide that information.
- If your company or vessel operates with a crew endurance management program, have you seen a reduction in workplace injuries? Can you provide data to support implementation of the crew endurance management program?
- If your company or vessel operates with a crew endurance management program, what measures have you undertaken to develop and implement a crew endurance management program? Did you make modifications to lighting,

noise and vibration? If so, what type of modification? How many crew endurance management program coaches does a vessel have? How many coaches are trained each year? Do you require training for other crew on your crew endurance management program system? How often?

- Would a crew endurance management program requirement alone, without a specific requirement that mariners on towing vessels obtain a required number of hours of uninterrupted sleep, such as 7–8 hours, be effective in combating fatigue?
- Would a crew endurance management program requirement alone, without a specific requirement that mariners on towing vessels obtain a required number of hours of uninterrupted sleep, such as 7–8 hours, reduce casualties and injuries?
- What existing crew endurance management programs could the Coast Guard consider equivalent to the Coast Guard's Crew Endurance Management System?
- Would a mandate to change the watch schedule or to implement and maintain a crew endurance management program impose economic burdens upon small businesses? If so, would these burdens be significant?
- What is the appropriate phase-in period or method for implementing hours of service and crew endurance management program standards or requirements?

The Coast Guard offers the following research and additional information regarding hours of service standards and requirements for managing crew endurance, the ability for a crewmember to maintain performance within safety limits while enduring job-related physiological and psychological challenges in order to inform public comment related to these issues:

The Coast Guard recognizes that the issue of operator fatigue is not new, nor is it an issue confined solely to the maritime industry. In 1989, the National Transportation Safety Board (NTSB) first addressed the issue of operator fatigue in three recommendations presented to the Secretary of Transportation and called for research, education, and revisions to existing regulations. In 1990, NTSB added these recommendations to its Most Wanted List. In 1999, NTSB sponsored a safety study that determined that operator fatigue remained widespread throughout the transportation industry. In 2006, NTSB reaffirmed their recommendation to the regulatory bodies for the Aviation, Marine, and Pipeline Industries to establish scientifically based hours of service regulations that set limits on hours of service, provide predictable work and rest schedules, and consider human sleep and rest requirements. As part of this recommendation, NTSB stated that "operating a vehicle without the operator's having adequate rest, in any mode of transportation, presents an unnecessary risk to the traveling public." These NTSB studies, recommendations, and other documents may be found at URL: *http://www.ntsb.gov.*

Sleep Loss and Its Consequences

In most work environments, many pressures and stressors impact workers' quality of life and performance. One important yet underestimated stressor is daily restriction of sleep (*See* National Sleep Foundation, "Sleep in America" poll. URL: *http://www.sleepfoundation.org* (2007)).

In many jobs, daily sleep restriction is unavoidable. Some professions such as health care, security, and transportation require working at night and, often, long work hours of 12 hours or more per day. In these fields, the effect of daily sleep loss on performance is crucial to safety. Often, in response to the daily workplace stressors, workers tend to stretch their capacity and compromise their nightly sleep, thus becoming chronically sleep deprived.

While the need for sleep varies considerably between individuals, studies show that for adults an average length of sleep between 7 and 8 ½ hours per night provides physiological and cognitive resources to support normal health and performance. Physiologically, at least two processes regulate sleep, one homeostatic and the other cyclic (also known as circadian) with a period of about 24 hours per day. The homeostatic process regulates energy availability and depends on the daily duration of sleep and of wakefulness; the need to sleep increases as wakefulness continues uninterrupted. The circadian process, also referred to as the body clock, regulates the time of the day when sleep is scheduled and also impacts the restoration and availability of cellular energy. In brief, the body clock abhors uncertainty; it prefers stable, daily sleep beginning at the same time(s). (*See* Paula Alhola & Paivi Polo-Kantola, "Sleep Deprivation: Impact on Cognitive Performance." Neuropsychiatric Diseases and Treatment, 553–567, Vol. 5 (2007).) These studies show that both of these processes work well with daily sleep periods lasting at least 7 uninterrupted hours, where that sleep occurs at consistent times from day to day. Additionally, significant disruptions of the timing of daily sleep onset, or restriction of the duration of sleep below 7 uninterrupted hours per day, result in significant impacts on human physiology, health, and performance.

While there are many unanswered questions regarding the functions of sleep and the effects of sleep loss, there is no question that sleep is critical for body restitution, like energy conservation, thermoregulation, and tissue recovery. In addition, a now well documented body of research demonstrates that sleep is essential for cognitive performance, especially memory consolidation. Daily sleep loss, instead, activates the sympathetic nervous system, causing release of adrenalin and cortisol, resulting in stress and impairments of the immune system and metabolism. Daily sleep loss is now linked with cellular insulin resistance, thus predisposing people who experience sleep restriction to abnormal glucose metabolism and diminished energy production. People who experience daily sleep loss usually suffer a decline in cognitive performance and changes in mood.

Performance Standards and Protection of Situational Awareness

Based on the Coast Guard's current research, the Coast Guard is considering requirements that would permit crewmembers on towing vessels: (a) Sufficient time off to obtain at least 8 uninterrupted hours of sleep or at least 7 hours of uninterrupted sleep and an additional sleep period in every 24 hour period; and (b) the means to prevent the disruption of circadian rhythms. Such standards would promote the daily restoration of crewmember cognitive and physiological resources and the protection of crewmember situational awareness and decision-making abilities.

Situational awareness refers to the capability to maintain a constant vigil over important information, understand the relationship among the various pieces of information monitored, and project this understanding into the near future to make critical decisions. The term "situational awareness" is a form of mental bookkeeping (David D. Woods, Leila J. Johannesen, Richard I. Cook & Nadine B. Sarter, Behind Human Error: Cognitive Systems, Computers, and Hindsight (1994)).

Crewmembers aboard towing vessels, whether working on the navigation watch, on deck, in engineering, or in the galley, must constantly maintain situational awareness to ensure safe operations. Situational awareness is essential to make informed decisions, act in a timely manner, and ultimately ensure operational safety, whether at sea or transiting through inland waterways, harbors, or coastal environments. Maintaining 24-hour vessel operations while successfully meeting navigational challenges such as inclement weather, vessel traffic, bridges, locks, and recreational vessels, requires all of the cognitive processes supporting situational awareness to be functioning in good working order.

Maintaining and updating situational awareness and making timely and accurate decisions in operational environments, such as the wheelhouse of a towing vessel, engineering, and on deck, necessitates a wide range of cognitive skills. In particular, a mariner must be able to:

- Appreciate a difficult and rapidly changing situation;
- Assess risk;
- Anticipate the range of consequences;
- Keep track of events;
- Update the big picture;
- Be innovative;
- Develop, maintain and revise plans;
- Remember when events occurred;
- Control mood and behavior;
- Show insights into one's own performance;
- Communicate effectively; and
- Avoid irrelevant distractions.

In addition to these skills, situational awareness and decision making also require cognitive abilities for rule-based skills of logical, critical, and deductive reasoning. A substantial body of research demonstrates that loss of sleep significantly degrades the cognitive skills (those 12 bulleted items listed above) necessary to establish and maintain situational awareness. (*See* Yvonne Harrison & James A. Horne, ''The Impact of Sleep Deprivation on Decision Making: A Review,'' Journal of Experimental Psychology: Applied, 236–249, Vol. 6 No. 3 (2000).

The prefrontal region of the brain facilitates the use of cognitive skills necessary for situational awareness. This region of the brain may shut down as it experiences daily sleep loss. (*See Id.;* Paula Alhola & Paivi Polo-Kantola, ''Sleep Deprivation: Impact on Cognitive Performance.'' Neuropsychiatric Diseases and Treatment, 553–567, Vol. 5 (2007).)

Effects of Sleep Loss on Situational Awareness: Distractions, Assimilation, and Judgment

Appreciation of a complex situation while avoiding distraction requires assimilation of large amounts of information in a short period of time. Loss of sleep increases visual and auditory distractions that decrease focused attention and, therefore, interferes with the assimilation of rapidly changing information. Daily loss of sleep results in less discrimination handling ambiguous material, less confidence, more openness to leading information, and more willingness to modify recollections of events. These effects also interfere with the correct assimilation of changing information. Even a single night of sleep loss can result in less appreciation of a complex situation. When subjected to sleep loss, study participants consistently applied more effort to pointless areas of their decision-making, which had little or no effective outcome in the task at hand. (*See* Yvonne Harrison & James A. Horne, ''The Impact of Sleep Deprivation on Decision Making: A Review.'' Journal of Experimental Psychology: Applied, 236–249, Vol. 6 No. 3 (2000).

Effects of Sleep Loss on the Ability To Track Events and To Develop and Update Strategies

One night of sleep loss leads to deterioration of planning skills, marked perseveration, and failure to revise original strategies in light of new information. Additionally, people who experience partial sleep loss are more likely to ''stay the course'' as opposed to changing strategies, even when it is apparent that the strategies are no longer appropriate. (*See Id.*).

Studies of accidents in maritime operations support the notion that loss of situational awareness plays a significant role in incidents attributed to human error. In a report published in 2005, discussed above in section III.D. of this preamble, TSAC reported that human factors accounted for 54 percent of the medium and high severity incidents and about 40 percent of the low severity incidents. Failures in situational awareness or task performance accounted for 69 percent of the medium and high severity incidents involving human factors. In a separate report in 2003, the Coast Guard—American Waterways Operators (AWO) Bridge Allision Working Group examined 459 bridge allisions (an allision is contact between a moving towing vessel and a stationary object such as bridge, dock, or moored vessel) and reported 78 percent were associated with pilot error and 12 percent with other operational errors. These reports may be found in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.'' Of even greater importance to the association of human error with loss of situational awareness was the finding that 68 percent of 435 cases showed critical decision-making errors on the part of the towing vessel operator.

These findings support the NTSB findings and recommendations that, in dynamically evolving operational scenarios, a loss of situational awareness leads to inadequate decision making and performance errors. On towing vessels, a typical work schedule alternates between 6 hours of work and 6 hours of rest, otherwise known as ''6 on/6 off.'' This schedule consistently restricts daily uninterrupted sleep below 6 hours (total uninterrupted sleep obtained in a 6 on/6 off watch schedule cannot exceed 6 hours) and does not deliberately ensure nighttime physiological adjustment (body clock adjusted for nighttime work and daytime sleep) when crewmembers work at night. As a result, when reviewing accidents involving human error, it is not possible to determine whether the degradation in situation awareness was from increasing sleep debt or from working against the physiological need to sleep. (*See* Yvonne Harrison and James A. Horne, ''The Impact of Sleep Deprivation on Decision Making: A Review.'' Journal of Experimental Psychology: Applied, 236–249, Vol. 6 No. 3 (2000); Paula Alhola and Paivi Polo-Kantola, ''Sleep Deprivation: Impact on Cognitive Performance.'' Neuropsychiatric Diseases and Treatment, 553–567, Vol. 5 (2007).)

Work Hours in the Towing Industry

Licensed crewmembers in the towing industry work approximately 84 working hours in a 7-day work week. See Department of Labor Bureau of Labor Statistics' Occupational Outlook Handbook, 2010–11, Water Transportation Occupations (*http://www.bls.gov/oco/pdf/ocos247.pdf*), p. 2. In most segments of the towing industry, towing companies must sustain 24-hour operations to provide customers with adequate transportation services and to compete with other carriers. Currently, a number of requirements governing hours of service for the shipping industry can be found in Title 46 of the U.S. Code. The law states that a towing vessel on a trip or voyage of less than 600 miles may divide its licensed officers and certain crewmembers, while at sea, into at least 2 watches (46 U.S.C. 8104(g)). The law further requires that licensed individuals on towing vessels that are at least 26 feet in length may not work more than 12 hours in a consecutive 24-hour period, except in an emergency (46 U.S.C. 8104(h)). Additionally, licensed individuals or crewmembers in the deck or engine departments, operating on the

Great Lakes, may not work more than 8 hours in one day or more than 15 hours in any 24-hour period, or 36 hours in any 72-hour period (46 U.S.C. 8104(c)).

As previously stated, the typical work schedule for towing vessels alternates between 6 hours of work and 6 hours of rest. This work/rest schedule is repeated every day, when possible, without changing reporting times. While the 6 on/6 off schedule provides consistent periods of work and rest from day to day, under the conditions of a 6 on/6 off schedule, sleep is restricted and sleep debt accumulates day after day, which gradually increases fatigue levels. (See Mikko Ha··rma··, Markku Partinen, Risto Repo, Matti Sorsa, and Pertti Siivonen, ''EFFECTS OF 6/6 AND 4/8 WATCH SYSTEMS ON SLEEPINESS AMONG BRIDGE OFFICERS.'' Chronobiology International, 25(2&3): 413–423, (2008)). Ultimately, under the 6 on/6 off schedule, fatigue is inevitable.

Physiological adaptation to nighttime work schedules is required to prevent crewmember fatigue. During nighttime watch periods, crewmembers experience the disparity between the need to sleep during the night and the requirement to work when they would normally be sleeping. (See Margareta Lützhöft, Anna Dahlgren, Albert Kircher, Birgitta Thorslund, and Mats Gillberg, ''Fatigue at Sea in Swedish Shipping—A Field Study.'' AMERICAN JOURNAL OF INDUSTRIAL MEDICINE 53:733–740 (2010). Adapting to nighttime work and daytime sleep requires specific natural and artificial light exposure regimens prior, during, and after the night watch to re-adjust physiological timing.

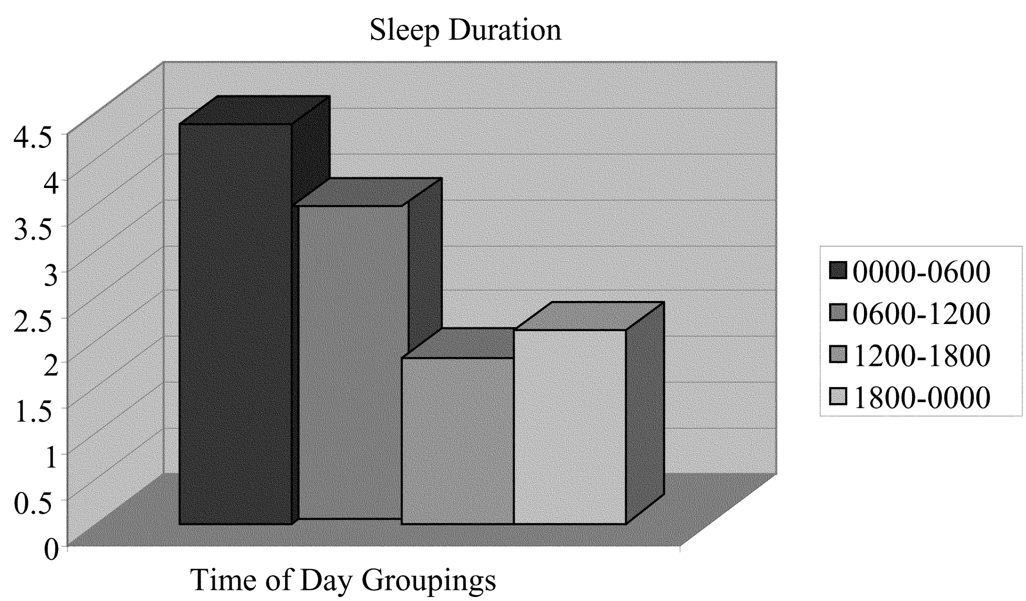
A recent study conducted at the Karolinska Institute in Sweden demonstrated that maritime officers working the 6 on/6 off schedule, without the opportunity to adjust their internal physiology to nighttime work and daytime sleep, consistently obtained less than 4.5 hours of sleep during a 6-hour period off, even when sleeping during the night (*see* Figure 1, below) (Claire A. Eriksen, Mats Gillberg & Peter Vestergren, ''Sleepiness and Sleep in a Simulated 'Six Hours on/Six Hours off' Sea Watch System.'' 23 Chronobiology International: The Journal of Biological and Medical Rhythm Research 1193–1202, (2006)). Officers sleeping during the night were not able to sleep longer than 5 hours per night, while officers sleeping during daytime hours slept less than 4 hours per sleep period. These data demonstrate that even when officers slept in comfortable bedrooms on shore, as was the case in this study, lack of physiological adaptation to the night work schedule resulted in further restrictions of sleep duration during daytime hours. Participants in this study share with crewmembers aboard domestic towing vessels both the 6 on/6 off watch schedule and the lack of opportunity to physiologically adapt to working nights and sleeping during the day.

Figure 1

Sleep in a simulated "Six Hours on/Six Hours off" Sea Watch System

Study conducted in the Karolinska Institute, Sweden

University of Umea, Umea, Sweden.



The Coast Guard provides training and information on fatigue management through the Crew Endurance Management Systems (CEMS) program. While this training and information has been available to the industry-at-large, companies report difficulty in providing appropriate artificial lighting for crewmember nighttime adaptation. Under the 6 on/6 off watch schedule, crewmembers work at night, against the natural physiological need to sleep, and under the influence of increasing sleep debt. Under these operational conditions, reduced situational awareness is inevitable. (*See* Yvonne Harrison and James A. Horne, ''The Impact of Sleep Deprivation on Decision Making: A Review.'' Journal of Experimental Psychology: Applied, 236–249, Vol.6 No.3 (2000); Paula Alhola and Paivi Polo-Kantola, ''Sleep Deprivation: Impact on Cognitive Performance.'' Neuropsychiatric Diseases and Treatment, 553–567, Vol. 5 (2007)).

The nexus between daily sleep restriction, relevant to the 6 on/6 off watch schedule, and cognitive impairment vital to the maintenance of situational awareness is demonstrated in a study conducted in 2002 at the Walter Reed Army Institute of Research. Researchers examined performance degradation and restoration in 66 research volunteers who were allowed 3, 5, 7, and 9 hours of continuous time in bed, each night for 7 consecutive days. Results of the study can be found in an article titled ''Patterns of Performance Degradation and Restoration During Sleep Restriction and Subsequent Recovery: A Sleep Dose-Response Study.'' This article may be found in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.''

As noted in the article, baseline performance was measured after participants were allowed 8 continuous hours of time in bed. Participants who had 9 consecutive hours of time in bed each night showed no impairment in performance. By contrast, participants who had 5 or 7 hours of time in bed showed slower reaction speeds. Participants in the 5-hour time in bed condition exhibited greater alertness deficit than in the 7-, 8-, and 9-hour time in bed conditions.

This study also highlighted the importance of recovery sleep on performance. After the 7 days of sleep restriction, participants were allowed 8 consecutive hours of time in bed for 3 days. During this 3-day recovery period, participants underwent neurobehavioral tests while awake. The 9-hour time in bed group showed no significant differences from the baseline. By contrast, the 3-hour time in bed group rapidly recovered when allowed 8 hours of time in bed on the first night, though their performance did not recover to baseline levels (8-hour time in bed). In fact, during the 3 days of sleep recovery, this group's performance levels never rose higher than those of participants whose sleep was restricted to 5 or 7 hours.

Disturbingly, while participants who had less than 8 continuous hours of time in bed did not report feeling sleepy, this group's performance and alertness levels decreased significantly, especially in the 5-hour and 3-hour time in bed groups. These data illustrate that people experiencing partial sleep deprivation do not easily recognize their own performance impairment.

A more recent study observed 48 healthy adults whose sleep was restricted to 4, 6, and 8 hours of time in bed per night for 14 days. The results are published in an article titled ''The Cumulative Cost of Additional Wakefulness: Dose-Response Effects on Neurobehavioral Functions and Sleep Physiology From Chronic Sleep Restriction and Total Sleep Deprivation.'' In this study, participants underwent neurobehavioral tests, while awake, every 2 hours to determine the effects of sleep restriction on their daytime performance. These tests included measures of attention/reaction time, working memory, mental agility, and subjective sleepiness. Taken together, the tests measured participants' cognitive abilities while they performed tasks requiring vigilance and mental tracking of critical information. Results showed that performance deteriorated significantly, as sleep loss accumulated over the 14 days.

Remarkably, the performance levels of participants who received less than 6 hours of time in bed per day, for 14 days, degraded as much as those of participants who had no time in bed for 2 days. Paradoxically, none of the sleep-restricted participants reported feeling sleepy.

The results of both studies highlighted here are important to towing operations, and as such were taken into consideration when we considered hours-of-service performance standards. While they cannot be said to prove without a doubt that when given less than 8 hours time in bed per night, a crewmember's alertness and cognitive abilities, and thus overall situational awareness, will decline, they do suggest that this is the case. Compounding the problem is the fact that sleepiness is unlikely to be reported, even when cognitive abilities are impaired.

In addition to reviewing the studies cited above, we used the Fatigue Avoidance Scheduling Tool (FAST) to determine the effects of sleeping less than 7–8 hours per day, even when considering two separate sleep periods. The FAST is the result of coordinated Department of Transportation (DOT) and Department of Defense (DOD) research efforts to develop and validate a comprehensive model to assess the effects of work and rest schedules on human health and performance. The Coast Guard also uses the FAST to assess, identify, and mitigate operational risks inherent in its own afloat, aviation, and ashore missions. Other agencies such as the Federal Railroad Administration (FRA) use the FAST for similar purposes. A full assessment, when applying the FAST, may be found in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.''

Figures 2 through 10 in the assessment, which can be found in the docket for this rulemaking, show results from modeling changes in human alertness and cognitive performance effectiveness as a result of working a variety of schedules. Figure 2 shows the impact of restricted sleep on performance and alertness of a crewmember working nights from 12 midnight–6 a.m. and during the day from 12 noon–6 p.m., simulating a two-watch system. In this case, the crewmember sleeps a total of 6 hours per day in two separate sleep periods, one occurring from 8 a.m.–10 a.m. and the other from 7 p.m.–11 p.m. All sleep considered in this example is of the highest quality, without any interruptions of any kind. This example simulates the crewmember sleeping 4 consecutive hours just prior to reporting for the night watch and 2 consecutive hours after the end of the watch. The FAST calculations reveal a pattern of degraded performance throughout the 30-day simulation. Under these circumstances, the daily alertness and performance function shows a degrading trend with alertness and performance levels comparable to someone with Blood Alcohol Concentration (BAC) levels of 0.05 percent, 0.08 percent, and 0.1 percent throughout the watch period.

Figure 3 shows the effect of interrupted sleep under the same schedule as the one used for the calculations depicted on figure 2. In this case, the FAST simulation includes two short interruptions of sleep per hour. This scenario simulates occasional sleep disruptions due to environmental noise, and results in brief wakefulness periods during every hour of sleep. In this instance, minor disruptions of the sleep period causes a rapid decrease in the performance efficiency curve. This decrease reaches levels comparable to performance below the 0.1 percent BAC level after only 3 consecutive days. Performance does not recover above the 0.1 percent BAC level throughout the 30-day assessment.

Figure 4 models the performance and alertness functions of a crewmember working 6 hours during the night (midnight–6 a.m.) and 6 hours during the day (noon–6 p.m.), but sleeping a total of 8 hours per day, 4 hours between 7 a.m.–11 a.m. and 4 hours between 7 p.m.–11 p.m. All sleep in this example is of the highest quality, without any interruptions. Examining the performance effectiveness function on Figure 4 reveals a daily degradation in alertness and performance that is comparable to 0.05 percent and 0.08 percent BAC levels throughout the night watch period. However, unlike the example shown on Figure 2, performance effectiveness begins a recovery trend on the seventh day. Recovery is not complete, as performance effectiveness does not climb above the 0.05 percent BAC performance level. This provides evidence that increasing daily sleep from 6 to 8 hours did improve performance efficiency, but it was not sufficient to prevent degradation of performance throughout the 30-day assessment.

Figure 5 shows the impact of minor interruptions of sleep per hour (two awakenings less than 1 minute long). The FAST algorithm reveals that, although this model iteration affords 8 total hours of sleep (adding both sleep periods), minor sleep disruptions result in significant degradation of performance. Performance effectiveness degrades below the 0.1 percent BAC level after the third day and remains below the 0.05 percent BAC level for the rest of the 30-day period of assessment. Both models explored in Figures 4 and 5 provide evidence that performance efficiency depends on the interaction between daily sleep duration and quality of sleep.

Figures 6, 7, 8, 9, and 10 provide results from modeling longer work and sleep periods in a two-watch system. The results shown in these models indicate that it is possible to prevent performance degradation in the two-watch system, but it requires the extension of the rest periods. The placement of the longest sleep period relative to the night watch is also important. Sleeping 6 hours soon after the night watch and 4 hours during the afternoon maintains performance efficiency within safe levels. Day watch models also showed high performance efficiency when consecutive sleep durations reached 6.5 hours.

Considering together the results from the FAST modeling, the scientific evidence showing that restricted sleep degrades performance via a degradation of cognitive abilities supporting situational awareness, and evidence of sleep restriction under the 6 on/6 off schedule, the Coast Guard believes that insufficient time off to allow for at least 7 hours of uninterrupted, daily sleep degrades cognitive abilities. Thus, the Coast Guard seeks additional data, information and public comment on potential requirements to increase uninterrupted sleep duration to a threshold of at least 7 consecutive hours in one of the two available off periods in the two-watch system to increase the probability that crewmembers will have the opportunity to restore the cognitive abilities necessary to maintain situational awareness, even if the sleep environment is not optimal.

The Coast Guard expects that any hours of service limitations, either adopted by industry or imposed through regulation, would address the need for inspected towing vessel operators to gradually alter the traditional 6 on/6 off watch schedules. The Coast Guard acknowledges, however, that requiring organizations and/or individuals to change behavior or adopt new behavioral patterns quickly, in response to abrupt regulatory requirements, can cause unintended disruptions in operation and service while the organizations and individuals adapt. The Coast Guard is thus requesting public comments on the appropriate phase-in period for a potential hours-of-service standard or requirement.

The Coast Guard is also considering the use of the light management process outlined in the Coast Guard's Crew Endurance Management System (CEMS) to gradually adapt crewmembers' physiology to early morning reporting times and to night work. Crewmembers' physiology would then allow them to sleep longer during the off watch periods. This gradual change would take place as crewmembers take advantage of the physiological adaptation to early morning reporting times and to night work afforded through the CEMS light management process.

The Coast Guard welcomes public comment on the issues addressed in this section related to potential hours of service standards and requirements.

Crew Endurance Management Programs

As discussed above, the CGMTA 2004 granted the Coast Guard authority to update the maximum hours of service standards currently regulating the towing industry. The CGMTA 2004 states that ''the Secretary may prescribe by regulation, requirements for maximum hours of service (including recording and recordkeeping of that service) of individuals engaged on a towing vessel that is at least 26 feet in length measured from end to end over the deck (excluding the sheer).'' 46 U.S.C. 8904(c). This Act authorized the Coast Guard to draft regulations to ensure that shipboard work practices do not compromise the safety of navigation and/or crewmembers due to unmitigated fatigue incidence. H.R. Conf. Rep. 108–617, 2004 U.S.C.C.A.N. 936, 951, 953. However, Congress directed the Coast Guard to carry out a demonstration project with the purpose of assessing the effectiveness and feasibility of the previously established Crew Endurance Management System (CEMS) on towing vessels, and report the results to Congress (Pub. L. 108–293, § 409(b), 118 Stat. 1044).

The Coast Guard developed CEMS in 1999 as a voluntary program to assist the commercial maritime industry in managing shipboard fatigue by coordinating improvements to shipboard diet, sleep, work environments, and watch schedules. CEMS established practices to protect crewmember health and performance. In developing CEMS, the Coast Guard recognized that a crewmember's physical endurance depends on efficient physiological energy production and management of risk factors such as poor diet, lack of exercise, and personal stress. Onboard access to exercise equipment, communications with family, and low-fat meals that consist of lean protein, complex carbohydrates, and fresh water are necessary to support a crewmember's physical endurance. However, while these activities are extremely important, the central objective of CEMS was and is to ensure that crewmembers have sufficient time off to obtain a daily minimum of 7–8 hours of uninterrupted, high-quality sleep. The Coast Guard has information suggesting that this daily sufficient sleep is crucial to maintain alertness and the cognitive abilities necessary to establish and maintain situational awareness and adequate physical capacity in the work environment.

Responding to the Congressional mandate, the Coast Guard conducted the CEMS demonstration project aboard towing vessels in 2005. The results of this project showed CEMS implementation was feasible, effective, and sustainable, but not all companies that participated adopted a watch scheduled that permitted a minimum of 7–8 hours of uninterrupted sleep. The report submitted to Congress, titled ''Report on Demonstration Project: Implementing the Crew Endurance Management System (CEMS) on Towing Vessels'' is available in the docket for this rulemaking, where listed above in section I.B. ''Viewing comments and documents.'' The Coast Guard welcomes public comments on this report, and all of the information and questions presented above in relation to potential hours of service and crew endurance management standards and requirements. As noted, after considering this additional information, the Coast Guard would later request public comment on specific hours of service or crew endurance management regulatory text if it seeks to implement such requirements.

V. Incorporation by Reference

Material proposed for incorporation by reference appears in §§ 136.112, 137.110, 138.110, 139.112, 141.105, 142.120, 143.120, and 144.110. You may inspect this material at U.S. Coast Guard Headquarters where indicated under **ADDRESSES**. Copies of the material are available from the sources listed in §§ 136.112, 137.110, 138.110, 139.112, 141.120, 142.115, 143.120, and 144.110. Before publishing a binding rule, we will submit this material to the Director of the **Federal Register** for approval of the incorporation by reference.

VI. Regulatory Analyses

We developed this proposed rule after considering numerous statutes and executive orders related to rulemaking. Below, we summarize our analyses based on 13 of these statutes or executive orders.

A. Regulatory Planning and Review

Executive Orders 13563 and 12866 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Executive Order 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility. This rule has been designated a ''significant regulatory action'' although not economically significant, under section 3(f) of Executive Order 12866. Accordingly, the rule has been reviewed by the Office of Management and Budget. A preliminary Regulatory Analysis (RA) is available in the docket where indicated under the ''Public Participation and Request for Comments'' section of this preamble. A summary of the RA follows:

This rulemaking would implement section 415 of the Coast Guard and Maritime Transportation Act of 2004. The intent of the proposed rule is to promote safer work practices and reduce casualties on towing vessels by ensuring that inspected towing vessels adhere to prescribed safety standards and adopted safety management systems. This proposed rule was developed in cooperation with the Towing Vessel Safety Advisory Committee (TSAC). The Coast Guard recognizes that establishing minimum standards for the towing vessel industry is necessary. Vessel operation, maintenance, and design must insure the safe conduct of towing vessels. The proposed rule would improve the safety and efficiency of the towing vessel industry.

In this NPRM, the Coast Guard proposes to require towing vessels subject to this rulemaking to be part of a safety management system or be subject to an alternative annual Coast Guard inspection regime. The proposed rule would require companies that operate inspected towing vessels to create a Towing Safety Management System (TSMS), continue with existing systems that comply with the provisions of the International Safety Management (ISM) Code, another system the Coast Guard determines to be equivalent to the TSMS, or be subject to an annual, Coast Guard inspection regime. The Coast Guard believes this rulemaking would create an environment that encourages safe practices.

This proposed rule would allow each towing vessel organization to customize its approach to meeting the requirements of the regulations, while it provides continuous oversight using audits, surveys, inspections, and reviews of safety data. This would improve the safety of towing vessels and provide greater flexibility and efficiency for towing vessel operators. As a result of this rulemaking, operators would be able to call upon third parties or the Coast Guard to conduct compliance activities when and where they are needed. *See* the ''Discussion of Proposed Rule'' section for a detailed discussion of this proposed rule and see the RA for a detailed discussion of costs, benefits and alternatives considered. Table 1 summarizes the impacts of this rulemaking.

TABLE 1—SUMMARY OF AFFECTED POPULATION, COSTS AND BENEFITS

Category	NPRM
Applicability	All U.S. flag towing vessels engaged in pushing, pulling, or hauling alongside, with exceptions for work boats and limited service towing vessels.
Affected Population	5,208 vessels, 1,059 companies.
Costs* ($ millions, 7% discount rate)	$18.4 (annualized), $129.5 (10-year).
Benefits ($ millions, 7% discount rate)	$28.5 (annualized), $200.1 (10-year).
Unquantified Benefits	Reduced congestion and delays from lock, bridge and waterway closures.

* These costs include the high estimate of industry costs plus government costs.

Affected Population

We estimate that 1,059 owners and operators (companies) would incur additional costs from this rulemaking. The rulemaking would affect a total of 5,208 vessels owned and operated by these companies. Our cost assessment includes existing and new vessels.

Costs

We estimated low and high costs to reflect the potential range of cost inputs for certain requirements, based on various sources of data, as discussed in the RA. During the initial phase-in period (years 1 and 2), we estimate the annual cost to industry of the rulemaking to range from $4.2 million to $5.7 million (non-discounted). After the initial phase-in, the annual costs to industry range from $10.9 million to $29.1 million (non-discounted). We estimate the total present value cost to industry over the 10-year period of analysis to range from $100.7 million to $119.9 million, discounted at 7 percent, and from $129.1 million to $153.9 million, discounted at 3 percent. Over the period of analysis, we estimate the annualized costs to industry range from

$14.3 million to $17.1 million at 7 percent and range from $15.1 million to $18.0 million at 3 percent. Table 2 summarizes the costs of this proposed rule to industry.

TABLE 2—INDUSTRY COST SUMMARY OF PROPOSED RULE

[$ millions]

Year	Undiscounted		Discounted			
			7%		3%	
	Low	High	Low	High	Low	High
1	$4.2	$5.5	$3.9	$5.2	$4.1	$5.4
2	4.3	5.7	3.8	5.0	4.1	5.4
3	10.9	12.2	8.9	10.0	9.9	11.2
4	12.1	13.4	9.2	10.3	10.7	11.9
5	14.6	16.4	10.4	11.7	12.6	14.2
6	16.7	18.2	10.9	12.1	13.8	15.2
7	23.7	29.1	14.8	18.1	19.3	23.7
8	23.7	29.1	13.8	16.9	18.7	23.0
9	23.7	29.1	12.9	15.8	18.2	22.3
10	23.7	29.1	12.1	14.8	17.7	21.7
Total *	157.4	187.9	100.7	119.9	129.1	153.9
Annualized	....	....	14.3	17.1	15.1	18.0

* Values may not total due to rounding.

We anticipate that the government will incur costs. For towing vessels that choose to comply with annual Coast Guard inspections, the government will incur costs to conduct those inspections. For other vessels choosing the TSMS option to comply, the government will incur costs to review applications for a TSMS, conduct random boardings and compliance examinations, and oversee third parties. We estimate the total present value cost to government over the 10-year period of analysis to be $9.6 million discounted at 7 percent and $12.0 million discounted at 3 percent. Annualized government costs are about $1.4 million under both 7 percent and 3 percent discount rates. We estimate the combined total 10-year present value cost of the rulemaking to industry and government to range from $110.3 million to $129.5 million, discounted at 7 percent, and from $141.1 million to $165.9 million, discounted at 3 percent. The combined annualized costs to industry and government range from $15.7 million to $18.4 million at 7 percent and from $16.5 million to $19.4 million at 3 percent.

Economic Impacts of Towing Vessel Casualties

Towing vessel casualties are incidents (*i.e.*, accidents) that involve the towing vessel and possibly other vessels such as barges, other commercial vessels, and recreational vessels. Towing vessel accidents can cause a variety of negative economic impacts, including loss of life, injuries, property damage, delays on transportation infrastructure, and damage to the environment.

Based on Coast Guard Marine Information for Safety and Law Enforcement (MISLE) data for the recent period of 2002–2007, towing vessel accidents are associated with 23 fatalities per year. Towing vessel accidents also result in an average of 146 reportable injuries per year (for the period of 2002–2007). Table 3 summarizes some of the negative impacts resulting from towing vessel accidents.

TABLE 3—NEGATIVE IMPACTS FROM TOWING VESSEL ACCIDENTS (2002–2007)

Impact	Average per year
Fatalities	23.
Injuries	146.
Accidents Causing Property Damage of $250,001 or more.	156.
Property Damage from Accidents of $250,001 or more.	$63.5 million.
Oil Spills	26.
Amount of Oil Spilled	184,717 gallons.
Congestion and Delays from lock, bridge and waterway closures.	Not quantified *.

* We present detailed information on delay and congestion impacts resulting from towing vessel accidents in the Regulatory Analysis available in the docket.

Benefits of the Towing Vessel Proposed Rule

The Coast Guard developed the requirements in the proposed rule by researching both the human factors and equipment failures that caused towing vessel accidents. We believe that the proposed rule would comprehensively address a wide range of causes of towing vessel accidents and supports the main goal of improving safety in the towing industry. The primary benefit of the proposed rule is an increase in vessel safety and a resulting decrease in the risk of towing vessel accidents and their consequences.

Based on Coast Guard investigation findings for towing vessel accident cases from 2002–2007, we estimate that the proposed rule would lead to significant reductions in fatalities, injuries, property damaged, and oil spilled. These improvements in safety are expected to occur over a 10-year period as the various provisions of the proposed rule are phased-in. We estimate total 10-year discounted benefits at $200.1 million discounted at 7 percent and $256.2 million discounted at 3 percent. Over the same period of analysis, we estimate annualized benefits of the proposed rule to be $28.5 million at a 7 percent discount rate and about $30.0 million at a 3 percent discount rate, respectively. Table 4 displays the monetized benefits of this proposed rule associated with reducing fatalities, injuries, property damage, and oil spilled, resulting from towing vessel accidents. During the phase-in period, we assume that companies take this time to implement the proposed rule and obtain their initial certificates of inspection. Therefore, we assign no benefits to those years.

TABLE 4—TOTAL BENEFITS

[$ millions] *

Year	Undiscounted	Discounted	
		7%	3%
1	$0.0	$0.0	$0.0
2	0.0	0.0	0.0
3	25.9	21.1	23.7
4	38.2	29.1	33.9
5	39.2	28.0	33.8
6	40.3	26.8	33.7
7	41.3	25.7	33.6
8	42.4	24.7	33.5
9	42.4	23.1	32.5
10	42.4	21.6	31.5
Total	312.0	200.1	256.2
Annualized		28.5	30.0

* Values may not total due to rounding.

Unquantified Benefits

These estimates do not include the value of benefits that we have not quantified, including preventing delays and congestion due to towing vessel accidents. We are unable to monetize the value of preventing other consequences of towing vessel accidents, including delays and congestion, due to a lack of data and information. However, as discussed in the Regulatory Analysis available in the docket, the potential value of other benefits could be substantial if towing vessel accidents cause long waterway, bridge, or road closures.

Avoided Delays and Waterway Disruptions

Every day, tons of goods worth millions of dollars transit the nation's waterways and the highways and railroads that pass alongside and over them. Towing vessel accidents that disrupt any one or more of these modes can be costly. The incident reports show that delays can range from a couple of hours for a damage assessment to a month or longer if a bridge has suffered major damage. For large accidents that result in long delays, the economic consequences may include the following:

- Productivity losses and operating costs for stalled barge and other traffic;
- Delays in the acquisition of production inputs that can impact timely operation of manufacturing or other processes;
- Blockages of U.S. exports that can result in decreased revenue from importing foreign companies;
- Loss of quality for industries dealing with time sensitive products or products with a limited shelf life, such as commercial fishing seafood processors, seafood dealers, or other food processors and manufacturers; and
- Reduced recreational opportunities, resulting in social welfare losses.

One example of a towing vessel accident having severe economic consequences on both traffic and the local economy is the collision of a barge with the Interstate 40 Bridge in Webbers Falls, Oklahoma, on May 26, 2002. The bridge was severely damaged and was closed for repairs for two months. The Interstate 40 Bridge is a major east-west route for both commercial and passenger traffic and carried approximately 22,000 vehicles per day. *See* the Regulatory Analysis, and the ''Report of the U.S. Coast Guard—American Waterways Operators Bridge Allision Work Group'' published in May 2003, both are available in the docket for additional details of this accident.

Towing vessel incidents are also known to result in blockages of rivers, port entrances, and other channels. This causes disruptions and delays to not only the towing industry, but other users of the waterways such as tankers, container ships, and recreational craft. The delay in use of the waterways can range from minutes (in the case of a grounding) to several days (in the case of an oil spill or an event that caused major damage to a lock or dam).

An example of an accident at a lock and dam involved the towboat Elizabeth M in January 2005. The Elizabeth M lost control of its barges shortly after exiting the Montgomery Locks and Dam on the Ohio River, south of Pittsburgh. The towboat and barges were swept over the dam and sunk in the waters below the dam, resulting in 4 fatalities. (*See* the ''Report of Investigation Sinking of the M/V ELIZAB[E]TH M (Official Number # 262962) and Six Barges with Four Fatalities on January 09, 2005 at the Montgomery Locks and Dam on the Ohio River at Mile Marker 31.7″ in the docket for additional details of this accident). According to Army Corps of Engineer records, the Montgomery Locks and Dam were closed for 28 hours after this incident. Additionally, restrictions on night travel as well as oil and chemical cargo continued for weeks after the incident. The use of an assist vessel to maneuver tows around the sunken barges and towboat at the foot of the dam was also required for several weeks.[1]

Based on data supplied by the Army Corps of Engineers, an average of 70.7 lock closures occurred because of towing vessel accidents over the past 6 years, causing an average of 209.6 hours of closures annually for the same period, with an average duration of the delay 3.0 hours (Table 5). For the same period, an average of nine events annually caused a lock closure of more than 6 hours (Table 6). Based on information from the Army Corps of Engineers, 6 hours or less is considered to be within the range of a normal operating delay. Over the past 6 years, towing vessel accidents involving locks have caused an average of 99.7 hours of delay beyond the 6-hour normal operating delay. For an event that causes over 6 hours of delay, the average duration of the delay over the 6-year

[1] U.S. Army Corps of Engineers, Pittsburgh District, ''Recovery Operations Expected to Start at Montgomery Lock,'' January 19, 2005.

period is 11.3 hours, with some causing double or quadruple that amount.

TABLE 5—NUMBER & DURATION OF LOCK DELAYS CAUSED BY TOWING VESSEL ACCIDENTS

Year	Number of events	Hours of delay	Average delay per event
2002	76	149.7	2.0
2003	64	182.9	2.9
2004	95	212.7	2.2
2005	59	375.6	6.4
2006	46	118	2.6
2007	84	218.5	2.6
6-Year Average	70.7	209.6	3.0

Source: USACE data on lock delays caused by towing vessel accidents provided in December 2008.

TABLE 6—NUMBER & DURATION OF LOCK DELAYS CAUSED BY TOWING VESSEL ACCIDENTS

[Exceeding 6 Hours]

Year	Number of events (exceeding 6 hours)	Hours of delay (exceeding 6 hours)	Average delay per event
2002	6	39.2	6.5
2003	11	71.59	6.5
2004	10	70.71	7.1
2005	11	274.46	25.0
2006	5	41.49	8.3
2007	10	100.47	10.0
6-Year Average	8.8	99.7	11.3

Source: USACE data on lock delays caused by towing vessel accidents provided in December 2008.

Other towing vessel accidents with large damages have occurred outside of the period of our benefit analysis. We do not include these accidents in the estimate of monetized benefits usually because the investigation is still pending or the impact details of the accident are still being developed. For example, in July 2008, a barge being pushed by a tow released 420,000 gallons of number 6 fuel oil in the Mississippi River near New Orleans, closing 100 miles of the Mississippi River to traffic for several days. The full value of clean up and response costs are still being tabulated for this event, but some estimates of the impact on the New Orleans economy range as high as $275 million per day. This event has been used by the Coast Guard in testimony before Congress to support the need for greater towing vessel safety.

Comparison of Costs to Benefits

The high estimate for total industry and government costs is $18.4 million (annualized at a 7% discount rate). The estimate for monetized benefits is $28.5 million (annualized at a 7% discount rate), based on the mitigation of risks from towing vessel accidents in terms of lives lost, injuries, oil spilled, and property damage. Subtracting the monetized costs from the monetized benefits yields a net benefit of $10.1 million. We also identified, but did not monetize, other benefits from reducing the risk of accidents that have secondary consequences of delays and congestions on waterways, highways, and railroads.

Overall, the regulatory analysis indicates that the preferred alternative provides owners and operators of towing vessels the ability to customize compliance to their individual business models, move the industry into inspected status, and improve safety.

Alternatives

The Coast Guard considered other alternatives to the current preferred alternative proposed in this NPRM. Alternative 1 would require that all towing vessels obtain and implement a TSMS and the Coast Guard would rely on third parties to audit and survey vessels to demonstrate compliance. Beyond an initial inspection, the Coast Guard would limit enforcement to review of evidence provided by third parties and owners and operators. Alternative 2 would require a traditional Coast Guard inspection, with no allowance for a TSMS or third party. Alternative 3 would require towing vessels to operate with a TSMS and undergo audits and surveys, but would not include part 140 requirements.

Alternative 1 has quantified benefits that only exceed costs by a small margin (0.1 million). Alternatives 2–3 have quantified costs that exceed quantified benefits thus resulting in net costs. A summary of the costs and benefits of the alternatives are presented in Table 7.

TABLE 7—SUMMARY OF ALTERNATIVES

[$ millions, 7% discount rate]

Alternative	Summary	Annualized cost	Annualized benefits	Net benefits or net costs *
Preferred Alternative (proposed in this NPRM)	Allow TSMS and third party review or Coast Guard inspection to demonstrate compliance.	$18.4	$28.5	$10.1
Alternative 1	Require TSMS for all towing vessels.	32.4	32.5	0.1
Alternative 2	Coast Guard inspection only. No third party	31.1	30.0	−1.1
Alternative 3	Require TSMS but no Part 140 requirements	31	28.3	−2.7

* Net benefits do not include unquantified congestion and delay benefits.

The RA available in the docket includes an analysis of the costs of this rulemaking by requirement and provides an assessment of potential monetized, quantified and non-quantified benefits of this rulemaking. The RA also contains details and analysis of other alternatives considered for this rulemaking.

B. Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this proposed rule would have a significant economic impact on a substantial number of small entities. The term ‘‘small entities’’ comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000.

A combined Regulatory Analysis and Initial Regulatory Flexibility Analysis discussing the impact of this proposed rule on small entities is available in the docket where indicated under the ‘‘Public Participation and Request for Comments’’ section of this preamble.

Based on available data, we determine that more than 92 percent of the businesses affected are small by the Small Business Administration (SBA) size standards. We analyzed revenue impacts on the initial phase-in and annual recurring costs of this proposed rule.

For the preferred alternative proposed in this NPRM, we determined that 25 percent of the small businesses would incur a significant economic impact (more than 1 percent impact on revenue) during the phase-in period in years 1 and 2. For the impact of annual recurring costs, we determined that potentially 49 percent of small businesses would incur a significant economic impact depending on the year.

In the ‘‘Regulatory Planning and Review’’ section of this NPRM, we summarized and compared the costs and benefits of other alternatives to the current preferred alternative proposed in this NPRM. Table 8 compares the impacts on small entities of the alternatives to the preferred alternative proposed in this NPRM for the phase-in period costs (years 1 and 2) and maximum recurring costs.

TABLE 8—ECONOMIC IMPACT OF ALTERNATIVES CONSIDERED ON SMALL ENTITIES

Alternative	Summary	Percentage of small entities with more than 1 percent cost impact on revenue	
		Phase-in costs	Recurring costs (maximum)
Preferred Alternative (proposed in this NPRM).	Allow TSMS and third party review or Coast Guard inspection to demonstrate compliance.	25%	49%
Alternative 1	Require TSMS for all towing vessels	72%	54%
Alternative 2	Coast Guard inspection only. No third party	71%	72%
Alternative 3	Require TSMS, but no Part 140 requirements	72%	50%

At this time, we have determined that this proposed rule would have a significant economic impact on a substantial number of small entities under section 605(b) of the Regulatory Flexibility Act. We are interested in the potential impacts from this proposed rule on small businesses and we request public comment on these potential impacts. If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this rulemaking would have a significant economic impact on it, please submit a comment to the Docket Management Facility at the address under **ADDRESSES**. In your comment, explain why, how, and to what degree you think this rule would have an economic impact on you.

C. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this proposed rule so that they can better evaluate its effects on them and participate in the rulemaking. If the proposed rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please consult Mr. Michael Harmon, Project Manager, CGHQ–1210, Coast Guard, telephone 202–372–1427. The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency’s responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247).

D. Collection of Information

This proposed rule would call for a collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520). As defined in 5 CFR 1320.3(c), ''Collection of Information'' comprises reporting, recordkeeping, monitoring, posting, labeling, and other, similar actions. The title and description of the information collections, a description of those who must collect the information, and an estimate of the total annual burden follow. The estimate covers the time for reviewing instructions, searching existing sources of data, gathering and maintaining the data needed, and completing and reviewing the collection.

Title: Towing Vessels—Title 46 CFR Subchapter M.

Summary of the Collection of Information: Owners and operators of inspected towing vessels would be required to either develop and maintain documentation for their safety management system and arrange periodic audits and surveys through third-party organizations, or to demonstrate compliance with the proposed Subchapter M to Coast Guard inspectors. Additional documentation would be required to obtain a Certificate of Inspection for each vessel, comply with crew and vessel operational safety standards, vessel equipment and system standards, procedures and schedules for routine tests and inspections of towing vessels and their onboard equipment and systems. The new requirements for third-party auditors and surveyors include obtaining Coast Guard approval and renewing it periodically. The Coast Guard would be burdened by reviewing required reports, conducting compliance examinations of towing vessels and overseeing third-party auditors and surveyors through approval and observation.

Need for Information: The information is necessary for the proper administration and enforcement of the proposed towing vessel inspection program.

Proposed Use of Information: The Coast Guard would use this information to document that towing vessels meet inspection requirements of Subchapter M.

Description of the Respondents: The respondents are the owners and operators of towing vessels, third-party auditors and surveyors, and the Coast Guard that would be required to complete various forms, reports and keep reports.

Number of Respondents: The number of respondents in the first year and recurring annually is 1,059 for owners and operators of 5,208 towing vessels and 175 third-party organizations.

Frequency of Response: Respondents would have to report and keep records with varying frequencies. The frequency of each regulation creating a new burden for corresponding respondents is detailed in the Regulatory Analysis.

Burden of Response: The burden of response for each regulation varies. Details are shown in the Regulatory Analysis with related assumptions and explanations both for the private sector respondents and the Coast Guard.

Estimate of Total Annual Burden: The estimated total annual burden for the initial phase-in (2) years (Years 1 and 2) and the first year after that phase-in period (Year 1) is 278,260 hours. This rule would create a new burden of 251,626 hours for the private sector and 26,634 hours for the Coast Guard for the first 3 years.

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), we will submit a copy of this proposed rule to the Office of Management and Budget (OMB) for its review of the collection of information.

We ask for public comment on the proposed collection of information to help us determine how useful the information is; whether it can help us perform our functions better; whether it is readily available elsewhere; how accurate our estimate of the burden of collection is; how valid our methods for determining burden are; how we can improve the quality, usefulness, and clarity of the information; and how we can minimize the burden of collection.

If you submit comments on the collection of information, submit them both to OMB and to the Docket Management Facility where indicated under **ADDRESSES**, by the date under **DATES**.

You need not respond to a collection of information unless it displays a currently valid control number from OMB. Before the Coast Guard could enforce the collection of information requirements in this proposed rule, OMB would need to approve the Coast Guard's request to collect this information.

E. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them.

It is well settled that States may not regulate in categories reserved for regulation by the Coast Guard. It is also well settled, now, that all of the categories covered in 46 U.S.C. 3306, 3703, 7101, and 8101 (design, construction, alteration, repair, maintenance, operation, equipping, personnel qualification, and manning of vessels), as well as the reporting of casualties and any other category in which Congress intended the Coast Guard to be the sole source of a vessel's obligations, are within the field foreclosed from regulation by the States. (*See* the decision of the Supreme Court in the consolidated cases of *United States* v. *Locke* and *Intertanko* v. *Locke,* 529 U.S. 89, 120 S.Ct. 1135 (March 6, 2000).) This proposed rule covers all of the foreclosed categories, as it establishes regulations covering a new category of inspected vessels. Because the States may not regulate within these categories, preemption under Executive Order 13132 is not an issue.

F. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or Tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any 1 year. Though this proposed rule would not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

G. Taking of Private Property

This proposed rule would not effect a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

H. Civil Justice Reform

This proposed rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

I. Protection of Children

We have analyzed this proposed rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and would not create an environmental risk to health or risk to safety that might disproportionately affect children.

J. Indian Tribal Governments

This proposed rule does not have Tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it would not have a substantial direct effect on one or more Indian Tribes, on the relationship between the Federal Government and Indian Tribes, or on the distribution of power and responsibilities between the Federal Government and Indian Tribes.

K. Energy Effects

We have analyzed this proposed rule under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. We have determined that it is not a ''significant energy action'' under that order. Though it is a ''significant regulatory action'' under Executive Order 12866, it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The Administrator of the Office of Information and Regulatory Affairs has not designated it as a significant energy action. Therefore, it does not require a Statement of Energy Effects under Executive Order 13211.

L. Technical Standards

The National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note) directs agencies to use voluntary consensus standards in their regulatory activities unless the agency provides Congress, through the OMB, with an explanation of why using these standards would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies.

This proposed rule uses the following voluntary consensus standards:

American Boat and Yacht Council (ABYC)

H–22—Electric Bilge Pump Systems, (2005)
H–24—Gasoline Fuel Systems, (2007)
H–25—Portable Fuel Systems for Flammable Liquids, (2003)
H–32—Ventilation of Boats Using Diesel Fuel, (2004)
H–33—Diesel Fuel Systems, (2005)
P–1—Installation of Exhaust Systems for Propulsion and Auxiliary Engines, (2002)
H–2—Ventilation of Boats Using Gasoline, (2000)
P–4—Marine Inboard Engines and Transmissions, (2004)
E–11—AC & DC Electrical Systems on Boats, (2003)

American Bureau of Shipping (ABS)

Rules for Building and Classing Steel Vessels for Service on Rivers and Intracoastal Waterways, (2007).

Rules for Building and Classing Steel Vessels Under 90 Meters (295 Feet) in Length, (2006).

American National Standards Institute (ANSI)

ANSI/ASQC 9001–2000, (2000).

International Maritime Organization

IMO Resolution A.760(18), Symbols Related to Life-Saving Appliances and Arrangements, (1993).

IMO Resolution A.520(13), Code of Practice for the Evaluation, Testing and Acceptance of Prototype Novel Life-Saving Appliances and Arrangements, (1993).

IMO Resolution A.688(17) Fire Test Procedures For Ignitability of Bedding Components, (1991).

International Organization for Standardization (ISO)

ISO Standard 14726: 2008 Ships and marine technology-Identification colours for the content of piping systems, (2008).

ISO Standard 9001–2000; Quality management systems—Requirements, (2000).

National Fire Protection Association (NFPA)

NFPA 10 (Chapter 7), Standard on Portable Fire Extinguishers, (2007)
NFPA 1971—Standard on Protective Ensembles for Structural Fire-Fighting and Proximity Fire-Fighting, (2007)
NFPA 750—Standard on Water Mist Fire Protection Systems, (2006)
NFPA 2001 Standard on Clean Agent Fire Extinguishing Systems, (2008)
NFPA 302–1998—Fire Protection Standard for Pleasure, and Commercial Motor Craft, (1998)
NFPA 70–2002—National Electric Code (NEC), (2002)

Society of Automotive Engineers (SAE)

SAE J1475–1996—Hydraulic Hose Fitting for Marine Applications, (1996)
SAE J1942–2005—Hose and Hose Assemblies for Marine Applications, (2005)

Underwriters Laboratories

UL 217—Single and Multiple Station Smoke Detectors, (2006)
UL 1275—Flammable Storage Cabinet, (2005)
UL 1104—Standards for Marine Navigation Lights, (1998)

The proposed sections that reference these standards, and the locations where these standards are available, are listed above in Section V. ''Incorporation by Reference.''

The Coast Guard also developed technical standards specifically for proposed subchapter M. They are used because we did not find specific voluntary consensus standards that could be adopted in this rule. Certain technical standards were developed in cooperation with TSAC. As an example, the TSMS was developed based on TSAC's recommendations for a safety management system appropriate for towing vessels. Requirements for third-party organizations also were developed specifically for this subchapter to ensure that individuals conducting activities authorized by this proposal have the appropriate experience with towing vessels. If you are aware of voluntary consensus standards that might apply, please identify them in a comment to the Docket Management Facility at the address under **ADDRESSES** and explain why they should be used.

M. Environment

We have analyzed this proposed rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have made a preliminary determination that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. A preliminary environmental analysis checklist supporting this determination is available in the docket where indicated under the ''Public Participation and Request for Comments'' section of this preamble. This proposed rule involves regulations concerning the training of maritime personnel, regulations concerning documentation, inspection and equipping of vessels and regulations concerning vessel operation safety standards. This action falls under section 2.B.2, figure 2–1, paragraphs (34) (c) and (d) of the Instruction and under section 6(a) of the ''Appendix to National Environmental Policy Act: Coast Guard Procedures for Categorical Exclusions, Notice of Final Agency Policy'' (67 FR 48243, July 23, 2002). We seek any comments or information that may lead to the discovery of a significant environmental impact from this proposed rule.

List of Subjects

46 CFR Part 2

Marine safety, Reporting and recordkeeping requirements, Vessels.

46 CFR Part 15

Reporting and recordkeeping requirements, Seamen, Vessels.

46 CFR Part 136

Incorporation by reference, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 137

Incorporation by reference, Marine safety, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 138

Incorporation by reference, Marine safety, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 139

Incorporation by reference, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 140

Marine safety, Occupational health and safety, Penalties, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 141

Incorporation by reference, Marine safety, Occupational health and safety, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 142

Fire prevention, Incorporation by reference, Marine safety, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 143

Hazardous materials transportation, Incorporation by reference, Marine safety, Reporting and recordkeeping requirements, Towing vessels.

46 CFR Part 144

Incorporation by reference, Marine safety, Reporting and recordkeeping requirements, Towing vessels.

For the reasons discussed in the preamble, the Coast Guard proposes to amend 46 CFR parts 2 and 15 and add 46 CFR subchapter M, consisting of parts 136, 137, 138, 139, 140, 141, 142, 143, and 144, as follows:

46 CFR Chapter I

PART 2—VESSEL INSPECTIONS

1. The authority citation for part 2 continues to read as follows:

Authority: 33 U.S.C. 1903; 43 U.S.C. 1333; 46 U.S.C. 2110, 3103, 3205, 3306, 3307, 3703; 46 U.S.C. Chapter 701; E.O. 12234, 45 FR 58801, 3 CFR, 1980 Comp., p. 277; Department of Homeland Security Delegation No. 0170.1. Subpart 2.45 also issued under the Act Dec. 27, 1950, Ch. 1155, secs. 1, 2, 64 Stat. 1120 (*see* 46 U.S.C. App. Note prec. 1).

§ 2.10–25 [Amended].

2. In § 2.10–25, in the definition of ''Sea-going towing vessel'', after the second occurrence of the word ''alongside'', add the phrase '', that has been issued a certificate of inspection under the provisions of subchapter I of this chapter''.

PART 15—MANNING REQUIREMENTS

3. The authority citation for part 15 continues to read as follows:

Authority: 46 U.S.C. 2101, 2103, 3306, 3703, 8101, 8102, 8103, 8104, 8105, 8301, 8304, 8502, 8503, 8701, 8702, 8901, 8902, 8903, 8904, 8905(b), 8906 and 9102; and Department of Homeland Security Delegation No. 0170.1.

§ 15.501 [Amended].

4. In § 15.501(b), remove the word ''Emergency'' and add, in its place, the word ''emergency''.

5. Revise § 15.505 to read as follows:

§ 15.505 Changes in the certificate of inspection.

All requests for changes in manning as indicated on the certificate of inspection must be to:

(a) The Officer in Charge, Marine Inspection (OCMI) who last issued the certificate of inspection; or

(b) The OCMI conducting the inspection, if the request is made in conjunction with an inspection for certification.

§ 15.510 [Amended].

6. In § 15.510, remove the word ''therefrom''.

§ 15.520 [Amended].

7. In § 15.520(b), remove the word ''OCMI'' and add, in its place, the words ''Officer in Charge, Marine Inspection (OCMI)''.

§ 15.610 [Amended].

8. In § 15.610(b)(2), remove the number ''12'' and add, in its place, the word ''four''.

9. Add § 15.535 to subpart D to read as follows:

§ 15.535 Towing vessels.

(a) The requirements in this section for towing vessels apply to a towing vessel certificated under subchapter M of this chapter.

(b) Except as provided in this paragraph, every towing vessel of at least 8 meters (at least 26 feet) in length, measured from end to end over the deck (excluding sheer), must be under the direction and control of a person licensed as master or mate (pilot) of towing vessels or as master or mate of vessels of greater than 200 gross register tons holding either an endorsement on his or her license for towing vessels or a completed Towing Officer's Assessment Record (TOAR) signed by a designated examiner indicating that the officer is proficient in the operation of towing vessels. This does not apply to any vessel engaged in assistance towing, or to any towing vessel of less than 200 gross register tons engaged in exploiting offshore minerals or oil if the vessel has sites or equipment so engaged as its place of departure or ultimate destination.

(c) Any towing vessel operating in the pilotage waters of the Lower Mississippi River must be under the control of an officer who holds a first-class pilot's license or endorsement for that route, or who meets the requirements of either paragraph (c)(1) or (2) of this section as applicable:

(1) To operate a towing vessel with tank barges, or a tow of barges carrying hazardous materials regulated under part N or O of this subchapter, an officer in charge of the towing vessel must have completed at least 12 round trips over this route as an observer, with at least 3 of those trips during hours of darkness, and at least 1 round trip of the 12 within the last 5 years.

(2) To operate a towing vessel without barges, or a tow of uninspected barges, an officer in charge of the towing vessel must have completed at least four round trips over this route as an observer, with at least one of those trips during hours of darkness, and at least one round trip of the four within the last 5 years.

10. Add 46 CFR subchapter M, consisting of parts 136 through 144, to read as follows:

SUBCHAPTER M—TOWING VESSELS

PART 136—CERTIFICATION

PART 137—VESSEL COMPLIANCE

PART 138—TOWING SAFETY MANAGEMENT SYSTEMS (TSMS)

PART 139—THIRD-PARTY ORGANIZATIONS

PART 140—OPERATIONS

PART 141—LIFESAVING

PART 142—FIRE PROTECTION

PART 143—MACHINERY AND ELECTRICAL SYSTEMS AND EQUIPMENT

PART 144—CONSTRUCTION AND ARRANGEMENT

PART 136—CERTIFICATION

Subpart A—General

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 136.100 Purpose.

This part sets out the applicability for subchapter M and describes the requirements for obtaining and renewing a Certificate of Inspection (COI).

§ 136.105 Applicability.

(a) This subchapter is applicable to all U.S.-flag towing vessels as defined in § 136.110 engaged in pushing, pulling, or hauling alongside, except:

(1) A vessel less than 26 feet (8 meters) in length measured from end to end over the deck (excluding the sheer), unless pushing, pulling, or hauling a barge that is carrying dangerous or hazardous materials;

(2) A vessel engaged in one or more of the following:

(i) A vessel used for assistance towing;

(ii) A vessel towing recreational vessels for salvage; or

(iii) A vessel transporting or assisting the navigation of recreational vessels within and between marinas and marina facilities, within a limited geographic area, as defined by the local Captain of the Port (COTP).

(3) Work boats operating exclusively within a worksite and performing intermittent towing within the worksite;

(4) Seagoing towing vessels over 300 gross tons subject to the provisions of Subchapter I of this chapter;

(5) A vessel inspected under other subchapters of this chapter that may perform occasional towing;

(6) A public vessel that is owned or bareboat chartered and operated by the United States, or by a State or political subdivision thereof, or by a foreign nation, except when the vessel is engaged in commercial service.

(7) A vessel which has surrendered its Certificate of Inspection (COI) and is laid up, dismantled, or otherwise out of service; and

(8) A propulsion unit used for the purpose of propelling or controlling the direction of a barge where the unit is controlled from the barge, not normally manned, and not utilized as an independent vessel.

(b) A vessel that is otherwise exempt from inspection may request application of this part.

§ 136.110 Definitions.

ABS Rules means the standards developed and published by the American Bureau of Shipping regarding the design, construction and certification of commercial vessels.

Accepted Safety Management System means a safety management system deemed by the Coast Guard to be equivalent to the requirements of this subchapter.

Accommodation space means any:

(1) Messroom;

(2) Lounge;

(3) Sitting area;

(4) Recreation room;

(5) Quarters;

(6) Toilet space;

(7) Shower room;

(8) Galley;

(9) Berthing space;

(10) Clothing-changing room; and

(11) A similar space open to individuals.

Approved third party means a third party approved by the Coast Guard in accordance with part 139 of this subchapter.

Assistance towing means towing a disabled vessel for consideration.

Audit means a systematic, independent, and documented examination to determine whether activities and related results comply with planned arrangements and whether these arrangements are implemented effectively and are suitable to achieve stated objectives. This examination includes a thorough review of appropriate reports, documents, records and other objective evidence to verify compliance with applicable requirements.

(1) The audit may include, but is not limited to:

(i) Examining records;

(ii) Asking responsible persons how they accomplish specific tasks;

(iii) Observing persons performing required tasks;

(iv) Examining equipment to insure proper maintenance and operation; and

(v) Checking training records and work environments.

(2) The audit may be limited to random selection of a representative sampling throughout the system that presents the auditor with sufficient objective evidence of system compliance.

Berthing space means a space that is intended to be used for sleeping and is provided with installed bunks and bedding.

Bollard pull means the maximum static pulling force that a towing vessel can exert on another vessel or an object when its propulsion engines are applying thrust at maximum horsepower.

Change in ownership means any change resulting in a change in the day-to-day operational control of an approved third party organization that conducts audits and surveys, or a change that results in a new entity holding more than 50 percent of the ownership of the approved third party organization.

Class Rules means the standards developed and published by a classification society regarding the design, construction and certification of commercial vessels.

Class II piping systems means those piping systems identified as class II in Table 56.04–2 of Subchapter F of this Chapter.

Coastwise means a route that is not more than 20 nautical miles offshore on any of the following waters:

(1) Any ocean;

(2) The Gulf of Mexico;

(3) The Caribbean Sea;

(4) The Bering Sea;

(5) The Gulf of Alaska; or

(6) Such other similar waters as may be designated by a Coast Guard District Commander.

Cold water means water where the monthly mean low water temperature is normally 15 degrees Celsius (59 degrees Fahrenheit) or less.

Conflict of Interest means a conflict between an individual's or an organization's private interests and the interests of another party with whom they are providing a service to or for, or in a capacity which serves the public good.

Consideration means an economic benefit, inducement, right, or profit including pecuniary payment accruing to an individual, person, or entity, but not including a voluntary sharing of the actual expenses of the voyage, by monetary contribution or donation of fuel, food, beverage, or other supplies.

Crewmember means all persons carried on board the vessel to provide navigation and maintenance of the vessel, its machinery, systems, and arrangements essential for propulsion and safe navigation, maintaining the tow, or to provide services to other persons aboard and shall not be construed as controlling the status of any person carried on board for purposes of 46 U.S.C. 30104.

Deficiency means a failure to meet minimum requirements of the vessel inspection laws or regulations.

Disabled vessel means a vessel that needs assistance, whether docked, moored, anchored, aground, adrift, or under way, but does not mean a barge or any other vessel not regularly operated under its own power.

Downstreaming means approaching a moored barge from upstream and landing with tow knees square against the upstream end of the barge.

Drydock means hauling out a vessel or placing a vessel in a drydock or slipway for an examination of all accessible parts of the vessel's underwater body and all through-hull fittings and appurtenances.

Element means a component of the safety management system, including policies, procedures, or documentation required to ensure a functioning towing safety management system.

Engine room means the enclosed area where any main-propulsion engine is located. It comprises all deck levels within that area.

Essential system means a system that is required to ensure a vessel's survivability, maintain safe operation, control the vessel, or ensure safety of on-board personnel, including systems for:

(1) Detection or suppression of fire;

(2) Emergency dewatering or ballast management;

(3) Navigation;

(4) Internal and external communication;

(5) Vessel control, including propulsion, steering, maneuverability and their essential auxiliaries (*e.g.*, lube oil, fuel oil, cooling water pumps, machinery space ventilation);

(6) Emergency evacuation and abandonment;

(7) Lifesaving;

(8) Control of a tow; and

(9) Any other marine engineering system identified in an approved Towing Safety Management System (TSMS) identified by the cognizant Officer in Charge, Marine Inspection (OCMI) as essential to the vessel's survivability, maintaining safe operation, controlling the vessel, or ensuring safety of onboard personnel.

Excepted vessel means a towing vessel that is:

(1) Used solely for any one or combination of the following services:

(i) Within a limited geographic area, such as a fleeting area for barges or a commercial facility, and used for restricted service, such as making up or breaking up larger tows;

(ii) For harbor-assist;

(iii) For response to emergency or pollution; or

(2) Exempted by the cognizant Officer in Charge, Marine Inspection (OCMI).

Existing towing vessel means a towing vessel, subject to inspection under this subchapter, that is not a new towing vessel, as defined in this section.

External Audit means an audit conducted by a party with no direct affiliation to the vessel or owner or managing operator being audited.

Fixed fire-extinguishing system means:

(1) A carbon dioxide system that satisfies 46 CFR subpart 76.15 and is approved by the Coast Guard;

(2) A manually operated, clean agent system that satisfies National Fire Protection Association (NFPA) Standard 2001 (incorporated by reference in § 136.112 of this subchapter) and is approved by the Coast Guard; or

(3) A manually operated, water mist system that satisfies NFPA Standard 750 (incorporated by reference in § 136.112 of this part) and is approved by the Coast Guard.

Fleeting area means a limited geographic area where individual barges are moored or assembled to make a tow. The barges are not in transport, but are temporarily marshaled and waiting for pickup by different vessels that will transport them to various destinations.

Fully attended means that a person who is appropriately trained to monitor and operate engineering equipment is located in the engine room at all times while the vessel is underway.

Galley means a space containing appliances with cooking surfaces that may exceed 121 degrees Celsius (250 degrees Fahrenheit) such as ovens, griddles, and deep fat fryers.

Great Lakes means a route on the waters of any of the Great Lakes and of the St. Lawrence River as far east as a straight line drawn from Cap de Rosiers to West Point, Anticosti Island, and west of a line along the 63rd meridian from Anticosti Island to the north shore of the St. Lawrence River.

Gross Tons means the gross ton measurement of the vessel under 46 U.S.C. chapter 145, Regulatory Measurement. For a vessel measured under only 46 U.S.C. chapter 143, Convention Measurement, the vessel's gross tonnage measured under 46 U.S.C. chapter 143 is used to apply all thresholds expressed in terms of gross tons.

Harbor of Safe Refuge means a port, inlet, or other body of water normally sheltered from heavy seas by land and in which a vessel can navigate and safely moor. The suitability of a location as a harbor of safe refuge will be determined by the cognizant Officer in Charge, Marine Inspection, and varies for each vessel, dependent on the vessel's size, maneuverability, and mooring gear.

Harbor-assist means the use of a towing vessel during maneuvers to dock, undock, moor, or unmoor a vessel or to escort a vessel with limited maneuverability.

Horsepower means the horsepower stated on the Certificate of Inspection (COI), which is the sum of the manufacturer's listed brake horsepower for all installed propulsion engines.

Independent means the equipment is arranged to perform its required function regardless of the state of operation, or failure, of other equipment.

Inland Waters means the navigable waters of the United States shoreward of the Boundary Lines as described in 46 CFR part 7, excluding the Great Lakes and, for towing vessels, excluding the Western Rivers.

Internal Audit means an audit that is conducted by a party which has a direct affiliation to the vessel or owner or managing operator being audited.

International Voyage means a voyage between a country to which SOLAS applies and a port outside that country. A country, as used in this definition, includes every territory for the international relations of which a contracting government to the convention is responsible or for which the United Nations is the administering authority. For the U.S., the term ''territory'' includes the Commonwealth of Puerto Rico, all possessions of the U.S., and all lands held by the U.S. under a protectorate or mandate. For the purposes of this subchapter, vessels are not considered as being on an ''international voyage'' when solely navigating the Great Lakes and the St. Lawrence River as far east as a straight line drawn from Cap des Rosiers to West Point, Anticosti Island and, on the north side of Anticosti Island, the 63rd meridian.

Lakes, bays, and sounds means a route on any of the following waters:

(1) A lake other than the Great Lakes;

(2) A bay;

(3) A sound; or

(4) Such other similar waters as may be designated by the cognizant Coast Guard District Commander.

Length means the horizontal distance measured from end to end over the deck, excluding the sheer. Fittings and attachments are not included in the length measurement.

Limited coastwise means a route that is not more than 20 nautical miles from a harbor of safe refuge.

Limited geographic area means a local area of operation, usually within a single harbor or port. The local Captain of the Port (COTP) determines limited geographic areas for each zone.

Machinery space means any enclosed space that either contains an installed, internal combustion engine, machinery, or systems that would raise the ambient temperature above 45 degrees Celsius in all environments the vessel operates in.

Major conversion means a conversion of a vessel that, as determined by the Coast Guard, substantially changes the dimensions or carrying capacity of the vessel, changes the type of vessel, substantially prolongs the life of the vessel, or otherwise changes the vessel such that it is essentially a new vessel.

Major non-conformity means an identifiable deviation which poses a serious threat to personnel, vessel safety, or a serious risk to the environment, and requires immediate corrective action, including the lack of effective and systematic implementation of a requirement of the Towing Safety Management System (TSMS).

Managing operator means an organization or person, such as the manager or the bareboat charterer of a vessel, who has assumed the responsibility for operation of the vessel from the ship owner and who, on assuming responsibility, has agreed to take over all the duties and responsibilities imposed by this subchapter.

New towing vessel means a towing vessel, subject to inspection under this subchapter, that:

(1) Was contracted for, or the keel which was laid on or after, [EFFECTIVE DATE OF FINAL RULE];

(2) Underwent a major conversion that was initiated on or after [EFFECTIVE DATE OF FINAL RULE]; or

(3) Is built without a contract, the keel laying date will be used to determine applicability.

Non-conformity means a situation where objective evidence indicates a non-fulfillment of a specified requirement.

Objective evidence means quantitative or qualitative information, records, or statements of fact pertaining to safety or to the existence and implementation of a safety management system element, which is based on observation, measurement, or testing that can be verified. This may include, but is not limited to towing gear equipment certificates and maintenance documents, training records, repair records, Coast Guard documents and certificates, surveys, or class society reports.

Oceans means a route that is more than 20 nautical miles offshore on any of the following waters:

(1) Any ocean;

(2) The Gulf of Mexico;

(3) The Caribbean Sea;

(4) The Bering Sea;

(5) The Gulf of Alaska; or

(6) Such other similar waters as may be designated by the cognizant Coast Guard District Commander.

Officer in Charge, Marine Inspection (OCMI) means an officer of the Coast Guard designated as such by the Coast Guard and who, under the direction of the Coast Guard District Commander, is in charge of a marine inspection zone, described in part 3 of this chapter, for the performance of duties with respect to the inspection, enforcement, and administration of vessel safety and navigation laws and regulations. The ''cognizant OCMI'' is the OCMI who has immediate jurisdiction over a vessel for the purpose of performing the duties previously described.

Oil or hazardous materials in bulk, as used in this subchapter, means that the towing vessel tows, pushes, or hauls alongside tank barge(s) certificated under subchapters D or O of this chapter.

Operating station means the principal steering station on the vessel, or the barge being towed or pushed, from which the vessel is normally navigated.

Owner means the owner of a vessel, as identified on the vessel's certificate of documentation or state registration.

Policy means a specific statement of principles or guiding philosophy that demonstrates a clear commitment by management; a statement of values or intent that provides a basis for consistent decision making.

Power and lighting circuit means a branch circuit as defined in NFPA 70–2002–National Electric Code (NEC) (incorporated by reference in § 136.112 of this subchapter) Article 100 that serves any essential system, a distribution panel, lighting, motor or motor group, or group of receptacles. Where multiple loads are served, the circuit is considered to be the conductor run that will carry the current common to all the loads. ''Power limited circuit'' conductors under Article 725 of the NEC and ''instrumentation'' conductors under Article 727 of the NEC are not considered to be power and lighting circuits.

Pressure vessel means a closed tank, cylinder or vessel containing gas, vapor or liquid, or a combination thereof, under pressure.

Procedure means a specification of a series of actions, acts, or operations which must be executed in the same manner in order to achieve a uniform approach to compliance with applicable policies.

Propulsor means a device (*e.g.,* propeller, water jet) which imparts force to a column of water in order to propel a vessel, together with any equipment necessary to transmit the power from the propulsion machinery to the device (*e.g.,* shafting, gearing, *etc.*).

Recognized Classification Society means the American Bureau of Shipping (ABS) or other classification society recognized by Coast Guard in accordance with Part 8 of this chapter.

Recognized hazardous conditions means conditions that are:

(1) Generally known among persons in the towing industry as causing, or likely to cause, death or serious physical harm to persons exposed to those conditions; and

(2) Routinely controlled in the towing industry.

Rivers means a route on any river, canal, or other similar body of water designated by the cognizant Officer in Charge, Marine Inspection.

Safety Management System means a structured and documented system enabling owner or managing operator and vessel personnel to effectively implement the owner or managing operator's safety and environmental protection policies and that is routinely exercised and audited in a way that ensures the policies and procedures are incorporated into the daily operation of the vessel.

Skiff means a small auxiliary boat carried onboard a towing vessel.

SOLAS means the International Convention for Safety of Life at Sea, 1974, as amended.

Survey means an examination of the vessel, its systems and equipment to verify compliance with applicable regulations, statutes, conventions, and treaties.

Terminal gear means the additional equipment or appurtenances at either end of the hawser or tow cable that connect the towing vessel and tow together and may include such items as thimbles, chafing gear, shackles, pendants and bridles.

Third-party organization means an organization approved by the Coast Guard to conduct independent verification that Towing Safety Management Systems or towing vessels comply with applicable requirements contained in this subchapter.

Tow means a combination of a towing vessel and one or more barges or a vessel not under its own power.

Towing vessel means a commercial vessel engaged in or intending to engage in the service of pulling, pushing, or hauling along side, or any combination of pulling, pushing, or hauling along side.

Towing Vessel Record (TVR) means a book, notebook, or electronic record used to document events required by this subchapter.

Travel time means the time that it takes for a crewmember to proceed to the towing vessel, inclusive of periods spent on commercial and non commercial carriers, transferring between carriers, layovers, and other delays.

Unsafe practice means a habitual or customary action or way of doing something which creates significant risk of harm to life, property, or the marine environment; or which contravenes a recognized standard of care contained in law, regulation, applicable international convention or international, national or industry consensus standard.

Warm water means water where the monthly mean low water temperature is normally more than 15 degrees Celsius (59 Fahrenheit).

Western Rivers means the Mississippi River, its tributaries, South Pass, and Southwest Pass, to the navigational demarcation lines dividing the high seas from harbors, rivers, and other inland waters of the United States, and the Port Allen-Morgan City Alternate Route, and that part of the Atchafalaya River above its junction with the Port Allen-Morgan City Alternate Route including the Old River and the Red River, and those waters specified in 33 CFR 89.25.

Workboat means a vessel that pushes, pulls, or hauls alongside equipment including dredging, construction, maintenance, or repair equipment within a worksite.

Worksite means an area specified by the cognizant Officer in Charge, Marine Inspection (OCMI) within which workboats are operated over short distances for dredging, construction, maintenance, or repair work and may include shipyards, owner's yards, or lay-down areas used by marine construction projects.

Work space means any area on the vessel where the crew may be present while on duty and performing their assigned tasks.

§ 136.112 Incorporation by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the **Federal Register** under 5 U.S.C 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the Coast Guard must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal regulations/ibr_locations.html.* Also, it is available for inspection at U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street, SW., Washington, DC 20593–0001, and is available from the sources listed in paragraph (b) of this section.

(b) The material approved for incorporation by reference in this part and the sections affected are:

National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02269–9101	
NFPA 750—Standard on Water Mist Fire Protection Systems, 2006	136.110
NFPA 2001—Standard on Clean Agent Fire Extinguishing Systems, 2008	136.110
NFPA 70–2002–National Electric Code (NEC), 2002	136.110
International Maritime Organization (IMO), 4, Albert Embankment, London, SE1 7SR, United Kingdom	
Resolution A. 520(13), Code of Practice for the Evaluation, Testing and Acceptance of Prototype Novel Life-Saving Appliances and Arrangements, 1983	136.115

§ 136.115 Equivalents.

(a) The Coast Guard may approve any arrangement, fitting, appliance, apparatus, equipment, calculation, information, or test, which provides a level of safety equivalent to that established by specific provisions of this subchapter. Requests for approval must be submitted to the Coast Guard via the cognizant Officer in Charge, Marine Inspection (OCMI). If necessary, the Marine Safety Center may require engineering evaluations and tests to demonstrate the equivalence of the substitute.

(b) The Coast Guard may accept compliance with the provisions of the International Convention for Safety of Life at Sea (SOLAS), 1974, as amended, applicable to the vessel's size and route as an equivalent to compliance with applicable requirements of this subchapter. Requests for a determination of equivalency for a particular vessel must be submitted to the Marine Safety Center via the cognizant OCMI.

(c) The Coast Guard may approve a novel lifesaving appliance or arrangement as an equivalent if it has performance characteristics at least equivalent to the appliance or arrangement required under this subchapter and has been evaluated and tested under International Maritime Organization (IMO) Resolution A.520(13) (incorporated by reference by § 136.112 of this part), Code of Practice for the Evaluation, Testing and Acceptance of Prototype Novel Life-Saving Appliances and Arrangements.

(d) The Coast Guard may accept alternative compliance arrangements in lieu of specific provisions of the Towing Safety Management System (TSMS) for the purpose of determining that an equivalent safety management system is in place onboard a vessel. The Coast Guard may consider the size and corporate structure of a vessel's management when determining the acceptability of an equivalent system. Requests for determination of equivalency must be submitted to Coast Guard via the cognizant OCMI.

(e) Alternate compliance arrangements must be documented within the TSMS applicable to the vessel.

§ 136.120 Special consideration.

Based on review of relevant information and the Towing Safety Management System applicable to the vessel, the cognizant Officer in Charge, Marine Inspection (OCMI) who issues the Certificate of Inspection may give special consideration to authorizing departures from the specific requirements, when unusual circumstances or arrangements warrant such departures and an equivalent level of safety is provided.

§ 136.130 Options for obtaining certification of a towing vessel.

(a) *TSMS or annual Coast Guard inspections.* This subchapter provides two options for obtaining a Certificate of Inspection for a towing vessel. The first option is annual inspection of the towing vessel by the Coast Guard, as discussed in §§ 136.150 through 136.165, part 137, and parts 140 through 144. The second option is to comply with the requirements for use of a towing safety management system (TSMS) and for use of approved third parties, as discussed in § 136.210 and parts 137 through 144 of this subchapter. Regardless of the option chosen, the Coast Guard is responsible for issuing a towing vessel Certificate of Inspection and may board a vessel at any time to verify compliance and take appropriate action. An owner or operator choosing the annual inspection option under §§ 136.150 through 136.170 may use a management system, vessel operations manual, or logbook to meet this subchapter's recordkeeping requirements.

(b) *Specifying option.* When submitting an application for a Certificate of Inspection, the owner or operator must specify which option he or she chooses for each particular towing vessel. Owners or operators may choose separate options for separate vessels within their fleet.

(c) *Changing option.* Requests to change options during the period of validity of an existing Certificate of Inspection must be accompanied by a new application to the OCMI for a new Certificate of Inspection. If the requirements for the new option are met, the OCMI will issue the vessel a new Certificate of Inspection.

(d) *Drydock examinations.* The option chosen for obtaining a vessel's Certificate of Inspection does not impact the frequency of required drydock examinations. Underwater inspections in lieu of a drydock (UWILD) can be used to obtain a Certificate of Inspection regardless of which option is chosen.

§ 136.140 Application for a Certificate of Inspection (COI).

Owners and operators must submit a written application for an inspection for certification to the cognizant OCMI. To renew a Certificate of Inspection (COI), owners and operators must submit an application at least 30 days before the expiration of the towing vessel's current certificate. Form CG–3752, Application for Inspection of U.S. Vessel, must be submitted to the OCMI at or nearest to the port where the vessel is located. When renewing a COI, the owner or operator must schedule an inspection for certification within the 3 months before the expiration date of the current COI.

§ 136.145 Inspection for certification.

(a) *Frequency of inspections.* After receiving an application for inspection, the OCMI will inspect a towing vessel located in his or her jurisdiction at least once every 5 years. The OCMI must ensure that every towing vessel is of a structure suitable for its intended route. If the OCMI deems it necessary, he or she may direct the vessel to be put in motion and may adopt any other suitable means to test the towing vessel and its equipment.

(b) *Nature of inspections.* The inspection for certification will include an inspection of the structure, pressure vessels, machinery and equipment. The inspection will ensure that the vessel is in satisfactory condition and fit for the service for which it is intended, and that it complies with the applicable regulations for such vessels. It will include inspections of the structure, pressure vessels and their appurtenances, piping, main and auxiliary machinery, electrical installations, lifesaving appliances, fire detecting and extinguishing equipment, pilot boarding equipment, and other equipment. The inspection will also determine that the vessel is in possession of a valid certificate issued by the Federal Communications Commission, if required. The inspector will also examine the vessel's lights, means of making sound signals, and distress signals, to ensure that they comply with the requirements of the applicable statutes and regulations. The inspector will also examine the vessel's pollution prevention systems and procedures.

(c) *Time of issuance of Certificate of Inspection.* The OCMI will issue a vessel a new Certificate of Inspection upon completing the inspection for certification.

§ 136.150 Annual and periodic inspections.

(a) *Annual inspection.* A towing vessel subject to subchapter M and choosing the Coast Guard option, or required to have the Coast Guard option, must undergo an annual inspection within 3 months before or after each anniversary date, except as specified in paragraph (b) of this section.

(1) Owners and operators must contact the cognizant OCMI to schedule an inspection at a time and place which he or she approves. No written application is required.

(2) Annual inspections will be similar to the inspection for certification but will cover less detail unless the cognizant marine inspector finds deficiencies or determines that a major change has occurred since the last inspection. If the cognizant marine inspector finds deficiencies or that a major change to the vessel has occurred, he or she will conduct a more detailed inspection to ensure that the vessel is in satisfactory condition and fit for the service for which it is intended. If the vessel passes the annual inspection, the marine inspector will endorse the vessel's current Certificate of Inspection.

(3) If the annual inspection reveals deficiencies in a vessel's maintenance, the owner or operator must make any or all repairs or improvements within the time period specified by the OCMI.

(4) Nothing in this subpart limits the marine inspector from conducting such tests or inspections he or she deems necessary to be assured of the vessel's seaworthiness.

(b) *Periodic inspection.* If an owner or operator chooses the Coast Guard inspection option, his or her vessel must undergo a periodic inspection within 3 months before or after the second or third anniversary of the date of the vessel's Certificate of Inspection. This periodic inspection will take the place of an annual inspection.

(1) Owners and operators must contact the cognizant OCMI to schedule an inspection at a time and place the OCMI approves. No written application is required.

(2) The scope of the periodic inspection is the same as that for the inspection for certification, as specified in § 136.145. The OCMI will ensure that the vessel is in satisfactory condition and fit for the service for which it is intended. If the vessel passes the periodic inspection, the marine inspector will endorse the vessel's current Certificate of Inspection.

(3) If the periodic inspection reveals deficiencies in a vessel's maintenance, the owner or operator must make any or all repairs or improvements within the time period specified by the OCMI.

(4) Nothing in this subpart limits the marine inspector from conducting such tests or inspections he or she deems necessary to be assured of the vessel's seaworthiness.

§ 136.165 Certificate of Inspection: conditions of validity.

To maintain a valid Certificate of Inspection, an owner or operator who chooses the Coast Guard option must complete the annual and periodic inspections within the periods specified in § 136.150(a) and (b), and the cognizant OCMI must endorse the vessel's Certificate of Inspection.

§ 136.170 Compliance for the Coast Guard option.

All owners or managing operators of more than one towing vessel required to have a Certificate of Inspection (COI) by this subchapter and choosing the Coast Guard inspection option, must ensure that each vessel under their ownership or control is issued a valid Certificate of Inspection (COI) according to the following schedule:

(a) Within 3 years of the effective date of this subchapter, 25 percent of the towing vessels must have onboard valid COIs;

(b) Within 4 years of the effective date of this subchapter, 50 percent of the towing vessels must have onboard valid COIs;

(c) Within 5 years of the effective date of this subchapter, 75 percent of the towing vessels must have onboard valid COIs; and

(d) Within 6 years of the effective date of this subchapter, 100 percent of the towing vessels must have onboard valid COIs.

§ 136.175 Approved equipment.

Where equipment in this subchapter is required to be of an approved type, such equipment requires the specific approval of the Coast Guard. A listing of approved equipment and materials may be found online at *http://cgmix.uscg.mil/equip/default.aspx.* Each Officer in Charge, Marine Inspection (OCMI) may be contacted for information concerning approved equipment and materials.

§ 136.180 Appeals.

Any person directly affected by a decision or action taken under this subchapter, by or on behalf of the Coast Guard, may appeal in accordance with § 1.03 in subchapter A of this chapter.

Subpart B—Certificate of Inspection

§ 136.200 Certificate required.

(a) A towing vessel may not be operated without having onboard a valid Certificate of Inspection (COI) issued by the U.S. Coast Guard.

(b) Each towing vessel certificated under the provisions of this subchapter must be in full compliance with the terms of the COI.

(c) If necessary to prevent delay of the vessel, a temporary COI may be issued to a towing vessel pending the issuance and delivery of the regular COI. The temporary COI must be carried in the same manner as the regular COI and is equivalent to the regular COI that it represents.

(d) A towing vessel on a foreign voyage between a port in the United States and a port in a foreign country, whose COI expires during the voyage, may lawfully complete the voyage without a valid COI provided the voyage is completed within 30 days of expiration and the certificate did not expire within 15 days of sailing on the foreign voyage from a U.S. port.

§ 136.203 Compliance for the TSMS option.

All owners or managing operators of more than one towing vessel required to have a Certificate of Inspection (COI) by this subchapter must ensure that each vessel under their ownership/control is issued a valid Certificate of Inspection (COI) according to the following schedule:

(a) Within 1 year of issuance of the Towing Safety Management System (TSMS) Certificate under § 138.305 of this subchapter, 25 percent of the towing vessels under their ownership/control must have onboard valid COIs;

(b) Within 2 years of issuance of the TSMS Certificate under § 138.305 of this subchapter, 50 percent of the towing vessels under their ownership/control must have onboard valid COIs;

(c) Within 3 years of issuance of the TSMS Certificate under § 138.305 of this subchapter, 75 percent of the towing vessels under their ownership/control must have onboard valid COIs; and

(d) Within 4 years of issuance of the TSMS Certificate under § 138.305 of this subchapter, 100 percent of the towing vessels under their ownership/control must have onboard valid COIs.

§ 136.205 Description.

A towing vessel's Certificate of Inspection describes the vessel, route(s) that it may travel, minimum manning requirements, minimum safety equipment carried, horsepower, and other information pertinent to the vessel's operations as determined by the Officer in Charge, Marine Inspection.

§ 136.210 Obtaining or renewing a Certificate of Inspection (COI).

(a) A Certificate of Inspection (COI) is obtained or renewed through the U.S. Coast Guard by making application to the cognizant Officer in Charge, Marine Inspection (OCMI) of the marine inspection zone in which the towing vessel is principally operated, or in which the owner or managing operator maintains management offices.

(b) The following documentation must be submitted:

(1) A completed Form CG 3752, ''Application for Inspection of U.S. Vessel'';

(2) Objective evidence that the owner or managing operator and vessel are in compliance with the Towing Safety Management System (TSMS) requirements of part 138 of this subchapter if a TSMS is applicable to the vessel;

(3) For initial certification—

(i) Objective evidence that the vessel's structure and stability, and essential systems comply with the applicable requirements contained in this subchapter for the intended route and service. This objective evidence may be in the form of a report issued by an approved third party or other means acceptable to the Coast Guard; and

(ii) Vessel particular information.

(4) For vessels utilizing the TSMS option, objective evidence that the vessel is equipped, maintained, and surveyed in compliance with §§ 137.200 and 137.300 of this subchapter; and

(5) A description of any modifications to the vessel.

(c) A towing vessel currently classed by a recognized classification society will be deemed to be in compliance with the design, construction, stability, equipment, and survey requirements of this subchapter.

(d) A towing vessel with a valid load line certificate issued in accordance with Subchapter E of this chapter may be deemed in compliance with the structural, drydocking, and stability requirements of this subchapter. The frequency of drydockings must meet the standards set forth in § 137.310 of this subchapter.

(e) A towing vessel with a valid International Safety Management Code certificate issued by a recognized classification society will be deemed in compliance with the TSMS requirements of this subchapter.

§ 136.215 Period of validity.

(a) A Certificate of Inspection (COI) for a towing vessel is valid for 5 years from the date of issue.

(b) A COI is invalid upon the expiration or revocation of the owner or managing operator Towing Safety Management System Certificate or International Safety Management Code Certificate.

(c) A COI may be suspended and withdrawn or revoked by the cognizant Officer in Charge, Marine Inspection at any time for noncompliance with the requirements of this subchapter.

§ 136.220 Posting.

(a) The original Certificate of Inspection (COI) must be framed under glass or other transparent material and posted in a conspicuous place onboard the towing vessel.

(b) If posting is impractical, such as in an open boat, the COI must be kept onboard in a weathertight container and readily available.

§ 136.225 Temporary certificate.

If necessary to prevent delay of the towing vessel, a temporary Certificate of Inspection (COI), Form CG–854, may be issued by the cognizant Officer in Charge, Marine Inspection (OCMI), pending the issuance and delivery of the regular COI. Such temporary COI must be carried in the same manner as the regular COI.

§ 136.230 Routes permitted.

(a) The area of operation for each towing vessel and any necessary operational limits are determined by the cognizant Officer in Charge, Marine Inspection (OCMI) and recorded on the vessel's Certificate of Inspection (COI). Each area of operation, referred to as a route, is described on the COI under the major headings ''Oceans,'' ''Coastwise,'' ''Limited Coastwise,'' ''Great Lakes,'' ''Lakes, Bays, and Sounds,'' or ''Rivers,'' as applicable. Further limitations imposed or extensions granted are described by reference to bodies of waters, geographical points, distances from geographical points, distances from land, depths of channel, seasonal limitations, and similar factors.

(b) Operation of a towing vessel on a route of lesser severity than those specifically described or designated on the COI is permitted unless expressly prohibited on the COI. The general order of severity of routes is: Oceans; coastwise; limited coastwise; Great Lakes; lakes, bays, and sounds; and rivers. The cognizant OCMI may prohibit a vessel from operating on a route of lesser severity than the primary route on which a vessel is authorized to operate, if local conditions necessitate such a restriction.

(c) When designating a permitted route or imposing any operational limits on a towing vessel, the cognizant OCMI may consider:

(1) The route-specific requirements of this subchapter;

(2) The performance capabilities of the vessel based on design, scantlings, stability, subdivision, propulsion, speed, operating modes, maneuverability, and other characteristics;

(3) The suitability of the vessel for nighttime operations and use in all weather conditions;

(4) Vessel operations in globally remote areas or severe environments not covered by this subchapter. Such areas may include, but are not limited to, polar regions, remote islands, areas of extreme weather, and other remote areas where timely emergency assistance cannot be anticipated; and

(5) The Towing Safety Management System applicable to the vessel, if the vessel has a TSMS.

§ 136.235 Certificate of Inspection (COI) amendment.

(a) An amended Certificate of Inspection (COI) may be issued at any time by the cognizant Officer in Charge, Marine Inspection (OCMI). The amended COI replaces the original, but the expiration date remains the same as that of the original. An amended COI may be issued to authorize and record a change in the dimensions, gross tonnage, owner, managing operator, manning, persons permitted, route permitted, conditions of operations, or equipment of a towing vessel, from that specified in the current COI.

(b) A request for an amended COI must be made to the cognizant OCMI by the owner or managing operator of the towing vessel at any time there is a change in the character of the vessel or in its route, equipment, ownership, operation, or similar factors specified in its current COI.

(c) Prior to the issuance of an amended COI, the cognizant OCMI may require that the owner or managing operator of the towing vessel provide an audit report. The report must:

(1) Be from an approved third-party organization and prepared in accordance with parts 138 and 139 of this subchapter; and

(2) Consider the change in the character of a vessel or in its route, equipment, ownership, operation, or similar factors specified in its current COI.

§ 136.240 Permit to proceed.

Permission to proceed to another port for repairs may be required for a towing vessel that is no longer in compliance with its Certificate of Inspection (COI). This may include damage to the vessel, failure of an essential system, or failure to comply with a regulation, including failure to comply with the Towing Safety Management System (TSMS) requirements, if appropriate.

(a) The vessel may proceed to another port for repair, if:

(1) In the judgment of the owner, managing operator, or master, the trip can be completed safely;

(2) If utilizing a TSMS, the TSMS addresses the condition of the vessel that has resulted in non-compliance and the necessary conditions under which the vessel may safely proceed to another port for repair;

(3) If utilizing a TSMS, the vessel proceeds as provided in the TSMS and does not tow while proceeding unless the owner or managing operator determines that it is safe to do so; and

(4) The owner or managing operator must notify the cognizant Officer in Charge, Marine Inspection (OCMI) in whose zone the non-compliance occurs or is discovered before the vessel proceeds and any other OCMI zones through which the vessel will transit.

(b) If utilizing a TSMS and this TSMS does not address the condition of the vessel that has resulted in non-compliance and the necessary conditions under which the vessel may safely proceed to another port for repair, the owner, managing operator, or master must apply to the cognizant OCMI in whose zone the non-compliance occurs or is discovered for permission to proceed to another port for repairs as follows:

(1) The application may be made electronically, in writing, or verbally. The cognizant OCMI may require a written description, damage surveys, or other documentation to assist in determining the nature and seriousness of the non-compliance;

(2) The vessel will not engage in towing, unless the cognizant OCMI determines it is safe to do so; and

(3) The permit may be issued by the Coast Guard on Form CG–948, ''Permit to Proceed to Another Port for Repairs,'' or in letter form and will state the conditions under which the vessel may proceed to another port for repair.

(c) The cognizant OCMI may require inspection of the vessel by a Coast Guard Marine Inspector or examination by an approved third-party surveyor prior to the vessel proceeding.

§ 136.245 Permit to carry excursion party or temporary extension or alternation of route.

(a) A towing vessel must obtain approval to engage in an excursion prior to carrying a greater number of persons than permitted by the Certificate of Inspection (COI) or a temporary extension or alteration of area of operation.

(b) The vessel may engage in an excursion, if:

(1) In the opinion of the owner, managing operator, or master the operation can be undertaken safely;

(2) If utilizing a TSMS, the TSMS addresses the temporary excursion

operation contemplated, the necessary conditions under which the vessel may safely conduct the operation, including the number of persons the vessel may carry, the crew required, and any additional lifesaving or safety equipment required;

(3) If utilizing a TSMS, the vessel proceeds as provided in the TSMS; and

(4) The owner, managing operator, or master notifies the cognizant Officer in Charge, Marine Inspection (OCMI) at least 48 hours prior to the temporary excursion operation. The cognizant OCMI may require submission of the pertinent provisions of the TSMS applicable to the vessel for review and onboard verification of compliance. If the cognizant OCMI has reason to believe that the TSMS applicable to the vessel is insufficient for the intended excursion, additional information requested and/or additional requirements may be imposed.

(c)(1) If a TSMS applicable to the vessel does not address the temporary excursion operation, then the owner or managing operator must submit an application to the cognizant OCMI. The application must state the intended route, number of passengers or guests, and any other conditions applicable to the excursion that exceed those specified in the COI.

(2) The cognizant OCMI may issue Form CG–949, ''Permit To Carry Excursion Party'' or a letter. The cognizant OCMI will indicate on the permit the conditions under which it is issued, the number of persons the vessel may carry, the crew required, any additional lifesaving or safety equipment required, the route for which the permit is granted, and the dates on which the permit is valid. The application may be made electronically, in writing, or verbally.

(d) The vessel may not engage in towing during the excursion, unless the cognizant OCMI determines it is safe to do so.

(e) The cognizant OCMI may require inspection of the vessel by a Coast Guard Marine Inspector, or examination by an approved third party.

§ 136.250 Load lines.

Each towing vessel operating outside the Boundary Line (as set forth in 46 CFR part 7) is subject to Subchapter E ''Load Lines'' as follows:

(a) On international voyages: If 79 feet (24 meters) or more in length and built on or after July 21, 1968, or 150 gross tons and over if built before that date;

(b) On domestic voyages, including Great Lakes: If 79 feet (24 meters) or more in length and built on or after January 1, 1986, or 150 gross tons and over if built before that date.

PART 137—VESSEL COMPLIANCE

Subpart A—General

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 137.100 Purpose.

This part describes the procedures owners or managing operators of towing vessels must use to demonstrate compliance with the requirements of this subchapter.

§ 137.105 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 137.110 [Reserved]

§ 137.115 Issuance of Certificate of Inspection (COI).

The owner or managing operator of a towing vessel must demonstrate that the vessel complies with this part to be eligible for Certificate of Inspection (COI) in accordance with § 136.210 of this subchapter.

§ 137.120 Responsibility for compliance.

(a) The owner and managing operator must ensure that the towing vessel is in compliance with this subchapter and other applicable laws and regulations at all times.

(b) Non-conformities and deficiencies must be corrected in a timely manner in order to prevent harm to life, property, and the marine environment.

§ 137.125 Towing Safety Management System (TSMS).

If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS must:

(a) Include policies and procedures to ensure compliance with this part; and

(b) Provide objective evidence that documents compliance with the TSMS.

§ 137.130 Program for vessel compliance for the TSMS option.

The owner or managing operator of a towing vessel choosing to utilize a TSMS must implement a program for vessel compliance. Each program must include:

(a) Owner or managing operator policy regarding the survey of towing vessels;

(b) Procedures for conducting towing vessel surveys, as described in this part;

(c) Procedures for reporting and correcting non-conformities and deficiencies;

(d) Identification of individual(s), and their qualifications, responsible for the management of the program; and

(e) Documentation of compliance activities.

§ 137.135 Reports and documentation required for the TSMS option.

(a) Reports detailing surveys of a towing vessel conducted by an approved third party must include:

(1) Vessel name;

(2) Other vessel identifier such as official number or state number;

(3) Name and business address of owner or managing operator;

(4) Date(s) of the survey;

(5) Date the Report of Survey was issued if different than the date the survey was concluded;

(6) Name of the surveyor;

(7) Name and business address of the approved third party the surveyor represents;

(8) Signature of the surveyor;

(9) A list or description of the items examined or witnessed;

(10) A descriptive listing of all non-conformities identified during the survey including those which were corrected during the course of the survey;

(11) A descriptive listing of:

(i) All non-conformities remaining at the end of the survey;

(ii) The required corrective action(s);

(iii) The latest date of required corrective action, not to exceed thirty days from date of discovery; and

(iv) Means by which the approved third party will verify that satisfactory corrective action has occurred.

(12) Identification of items that need to be repaired or replaced before the vessel continues in service; and

(13) A statement that the vessel complies with the applicable requirements of this subchapter and is fit for service and route, subject to correction of non-conformities.

(b) For a vessel subject to an audited program, the owner or managing operator must provide objective evidence of compliance with this part in accordance with the Towing Safety Management System applicable to the vessel.

Subpart B—Surveys for Certification for the TSMS Option

§ 137.200 Frequency of survey.

The owner or managing operator of a towing vessel must document compliance with this subpart as follows:

(a) Prior to obtaining the vessel's initial Certificate of Inspection (COI), the owner or managing operator must provide to the Coast Guard a report of a survey as described in § 137.215 that demonstrates that the vessel complies with the survey requirements of this part.

(b) For re-issuance of the vessel's COI:

(1) Provide objective evidence of a periodic survey as described in § 137.205 of this part; or

(2) Provide objective evidence of an audited program as described in § 137.210 of this part.

§ 137.205 Periodic survey.

(a) The owner or managing operator of a towing vessel who demonstrates compliance through a periodic survey must:

(1) Have the vessel surveyed annually by an approved third-party surveyor;

(2) Ensure the survey is conducted in accordance with 137.215;

(3) Ensure the survey is conducted within 3 months of the anniversary of the issuance of the Certificate of Inspection;

(4) Ensure the Towing Safety Management System (TSMS) applicable to the vessel includes policies and procedures for complying with this section; and

(5) Make the applicable sections of the TSMS available to the surveyor.

(b) The approved third party must issue a report which meets the requirements of § 137.135 of this part.

§ 137.210 Audited program.

(a) The owner or managing operator of a towing vessel may demonstrate vessel compliance through an audited program. The Towing Safety Management System applicable to the vessel must include:

(1) Procedures for surveying and testing contained in § 137.215 of this part;

(2) Equipment, systems, and onboard procedures to be surveyed;

(3) Identification of items that need repair or replacement before the vessel continues in service;

(4) Procedures for documenting and reporting non-conformities and deficiencies;

(5) Procedures for reporting and correcting major non-conformities;

(6) The responsible person(s) in management who has the authority, to:

(i) Stop all vessel operations pending correction of non-conformities and deficiencies;

(ii) Oversee vessel compliance activities; and

(iii) Track and verify that non-conformities and deficiencies were corrected.

(7) Procedures for recordkeeping.

(b) The owner or managing operator is not required to survey the items as described in § 137.220 of this part as one event, but may survey items on a schedule over time, provided that the interval between successive surveys of any item does not exceed 1 year, unless otherwise prescribed.

(c) Prior to placement into an audited program, a towing vessel must successfully complete an initial audit by an approved third party. Then, the vessel must be audited in accordance with the provisions of part 138 of this subchapter.

(d) If the cognizant Officer in Charge, Marine Inspection (OCMI) has reason to believe that an audited program is deficient, that OCMI may:

(1) Require an audit or survey of the vessel in the presence of a representative of the cognizant OCMI;

(2) Increase the frequency of the audits; or

(3) Require that the vessel comply with the periodic survey requirements of § 137.205 of this part.

(4) Require any specific action within his power and authority deemed appropriate.

(5) For continued deficient audits, remove the vessel and or owner or managing operator from the TSMS system.

§ 137.215 General conduct of survey.

(a) When conducting a survey of a towing vessel as required by this subpart, the surveyor must determine that the item or system functions as designed, is free of defects or modifications that reduce its effectiveness, is suitable for the service intended, and functions safely in a manner consistent for vessel type, service and route.

(b) The survey must address the items in § 137.220 of this part as applicable, and include:

(1) A review of certificates and documentation held on the vessel;

(2) Visual examination and tests of the vessel and its equipment and systems in order to confirm that their condition is properly maintained and that proper quantities are onboard;

(3) Observation of drills or training to determine that the program of drills and training is carried out properly; and

(4) Visual examination to confirm that unapproved modifications were not made to the vessel or its equipment.

(c) The thoroughness and stringency of the survey will depend upon the condition of the vessel and its equipment.

(d) The owner or managing operator must notify the cognizant Officer in Charge, Marine Inspection (OCMI) when the condition of the vessel, its equipment, systems, or operations, create an unsafe condition.

(e) The cognizant OCMI may require that the owner or managing operator provide for the attendance of an approved third-party surveyor or auditor to assist with verifying compliance with this part.

§ 137.220 Scope.

The owner or managing operator of a towing vessel must examine or have examined the following systems, equipment, and procedures to ensure that the vessel and its equipment are suitable for the service for which the vessel is certificated:

(a) *Towing Safety Management System (TSMS).* (1) Verify that the vessel is enrolled in a TSMS that complies with part 138 of this subchapter;

(2) Verify that the policies and procedures applicable to the vessel are available to the crew;

(3) Verify that internal and external audits are conducted in accordance with the approved TSMS; and

(4) Verify that recordkeeping requirements are met.

(b) *Hull structure and appurtenances.* Verify that the vessel complies with part 144 of this subchapter and examine the condition, and where appropriate, witness the operation of the following:

(1) All accessible parts of the exterior and interior of the hull, the watertight bulkheads, and weather decks;

(2) All watertight closures in the hull, decks, and bulkheads, including through hull fittings and sea valves;

(3) Superstructure, masts, and similar arrangements constructed on the hull;

(4) Railings and bulwarks and their attachments to the hull structure;

(5) The presence of guards or rails in dangerous places;

(6) All weathertight closures above the weather deck and the provisions for drainage of sea water from the exposed decks;

(7) Watertight doors, verifying local and remote operation and proper fit;

(8) All accessible interior spaces to ensure that they are adequately ventilated and drained, and that means of escape are maintained and operate as intended; and

(9) Vessel markings.

(c) *Machinery, fuel, and piping systems.* Verify that the vessel complies with applicable requirements contained in part 143 of this subchapter and examine the condition, and where appropriate, witness the operation of the following:

(1) Engine control mechanisms, including primary and alternate means, if the vessel is equipped with alternate means, of starting machinery, directional controls, and emergency shutdowns;

(2) All machinery essential to the routine operation of the vessel, including generators and cooling systems;

(3) All fuel systems, including fuel tanks, tank vents, piping, and pipe fittings;

(4) All valves in fuel lines, including local and remote operation;

(5) All overboard discharge and intake valves and watertight bulkhead pipe penetration valves;

(6) Means provided for pumping bilges; and

(7) Machinery shut-downs and alarms.

(d) *Steering systems.* Examine the condition and, where appropriate, witness the operation of the following:

(1) Steering systems and equipment ensuring smooth operation;

(2) Auxiliary means of steering, if installed; and

(3) Alarms.

(e) *Pressure vessels and boilers.* Examine, maintain, repair, and test unfired pressure vessels and boilers in accordance with subpart C of part 143 of this chapter.

(f) *Electrical.* Verify vessel complies with applicable requirements contained in part 143 of this subchapter and examine the condition and, where appropriate, witness the operation of the following:

(1) All cables, as far as practicable, without undue disturbance of the cable or electrical apparatus;

(2) Circuit breakers, including testing by manual operation;

(3) Fuses, including ensuring the ratings of fuses are suitable for the service intended;

(4) All generators, motors, lighting fixtures, and circuit interrupting devices;

(5) Batteries including security of stowage;

(6) Electrical apparatus, which operates as part of or in conjunction with a fire detection or alarms system installed onboard the vessel, to ensure operation in case of fire; and

(7) All emergency electrical systems, including any automatic systems if installed.

(g) *Lifesaving.* Verify vessel complies with applicable requirements contained in part 141 of this subchapter and examine the condition of lifesaving equipment and systems as follows:

(1) Vessel is equipped with the required number of lifejackets, work vests, and immersion suits;

(2) Serviceable condition of each lifejacket, work vest, and marine buoyant device;

(3) Each lifejacket, other personal floatation device, and other lifesaving device found to be defective and incapable of repair, was destroyed;

(4) Each item of lifesaving equipment found to be defective has been repaired or replaced;

(5) Each piece of expired lifesaving equipment has been replaced;

(6) Operation of each rescue boat and its launching appliance and survival craft launching appliance in accordance with Subchapter W of this chapter;

(7) Servicing of each inflatable liferaft, inflatable buoyant apparatus, and inflatable lifejacket as required by Subchapter W of this chapter;

(8) Operation of each hydrostatic release unit as required by Subchapter W of this chapter; and

(9) Vessel's crew conducted abandon ship and man overboard drills under simulated emergency conditions.

(h) *Fire protection.* Verify vessel complies with applicable requirements contained in part 142 of this subchapter and examine or verify fire protection equipment and systems as follows:

(1) Vessel is equipped with the required fire protection equipment for the vessel's route and service;

(2) Examinations, testing, and maintenance as required by § 142.240 of this subchapter are performed; and

(3) Training requirements of § 142.245 of this subchapter are carried out.

(i) *Towing gear.* Verify vessel complies with applicable requirements contained in parts 140 and 143 of this subchapter and examine or verify the condition, and where appropriate, the operation of the following:

(1) Deck machinery including controls, guards, alarms and safety features;

(2) Hawsers, wires, bridles, push gear, and related vessel fittings for damage or wear; and

(3) Vessel complies with 33 CFR part 164, if applicable.

(j) *Navigation equipment.* Verify vessel complies with applicable requirements contained in part 140 of this subchapter and examine or verify the condition and, where appropriate, the operation of the following:

(1) Navigation systems and equipment;

(2) Navigation lights;

(3) Navigation charts or maps appropriate to the area of operation and corrected up to date;

(4) Operation of equipment and systems necessary to maintain visibility through the pilothouse windows; and

(5) Vessel complies with 33 CFR Part 164, if applicable.

(k) *Sanitary examination.* Examine quarters, toilet and washing spaces, galleys, serving pantries, lockers, and similar spaces to ensure that they are clean and decently habitable.

(l) *Unsafe practices.* (1) Verify that all observed unsafe practices, fire hazards, and other hazardous situations are corrected, and all required guards and protective devices are in satisfactory condition; and

(2) Ensure that bilges and other spaces are free of excessive accumulation of oil, trash, debris, or other matter that might create a fire hazard, clog bilge pumping systems, or block emergency escapes.

(m) *Vessel personnel.* Verify that the:

(1) Vessel is manned in accordance with the vessel's Certificate of Inspection;

(2) Crew is maintaining vessel logs and records in accordance with applicable regulations and the TSMS appropriate to the vessel;

(3) Crew is complying with the crew safety and personnel health requirements of part 140 of this subchapter;

(4) Crew has received training required by parts 140, 141, and 142 of this subchapter; and

(5) Vessel complies with part 140 of this subchapter.

(n) *Prevention of oil pollution.* Examine the vessel to ensure compliance with the oil pollution prevention requirements set forth in § 140.655 of this subchapter.

(o) *Miscellaneous systems and equipment.* Examine all items in the vessel's outfit, such as ground tackle, markings, and placards, which are required to be carried by the regulations in this subchapter.

Subpart C—Drydock and Internal Structural Surveys

§ 137.300 Documenting compliance for the TSMS option.

The owner or managing operator of a towing vessel must document compliance with this subpart as follows:

(a) Except as provided in paragraph (c) of this section, the owner or managing operator must provide to the Coast Guard a report of a survey as described in § 137.215 of this part that demonstrates that the vessel complies with the drydock and internal structural survey requirements of this part, prior to obtaining the vessel's initial Certificate of Inspection (COI).

(b) For re-issuance of the vessel's COI:

(1) Provide objective evidence of a periodic survey as described in § 137.310 of this part; or

(2) Provide objective evidence of an audited program as described in § 137.315 of this part.

(c) Objective evidence of compliance with the load line assignment, certification, and marking requirements in subchapter E (Load lines) of this chapter must be provided as described in § 137.320 of this part.

§ 137.305 Intervals for drydock and internal structural examination.

(a) Regardless of the option chosen to obtain a COI, each towing vessel must undergo a drydock examination and internal structural examination at the following intervals:

(1) A vessel that is exposed to salt water more than 6 months in any 12-month period since the last survey must undergo a drydock and an internal structural survey at least twice every 5 years, with not more than 36 months between drydockings; and

(2) A vessel that is exposed to salt water not more than 6 months in any 12-month period since the last survey must undergo a drydock and an internal structural survey at least once every 5 years.

(b) The cognizant Officer in Charge, Marine Inspection may require further examination of the vessel whenever damage or deterioration to hull plating or structural members is discovered or suspected that may affect the seaworthiness of a vessel. This may include examination of the vessel on drydock, including:

(1) Internal structural examination of any affected space of a vessel, including fuel tanks;

(2) Removal of the vessel from service to assess the extent of the damage and to effect permanent repairs; or

(3) Adjusting the drydock examination intervals to monitor the vessel's structural condition.

§ 137.310 Periodic survey for the TSMS option.

(a) The owner or managing operator of a towing vessel may demonstrate that the vessel complies with § 137.330 of this part by having an approved third-party surveyor conduct a survey of the vessel.

(b) The survey must be conducted at the intervals prescribed in § 137.305 of this part.

(c) The Towing Safety Management System (TSMS) applicable to the vessel must include policies and procedures for complying with this section.

(d) The applicable sections of the TSMS must be made available to the surveyor conducting the survey.

(e) The drydock and internal structural survey must be documented in a report that complies with the information required in § 137.205(b) of this part.

§ 137.315 Audited program for the TSMS option.

(a) The owner or managing operator of a towing vessel may demonstrate compliance with this subpart through an audited program. The Towing Safety Management System (TSMS) applicable to the vessel must include:

(1) An examination that meets the requirements contained in § 137.325 of this part;

(2) Qualifications of the personnel authorized to carry out examinations that are comparable to the requirements of an approved third-party surveyor as provided for in § 139.130 of this subchapter;

(3) Procedures for documenting and reporting non-conformities and deficiencies;

(4) Procedures for reporting and correcting major non-conformities;

(5) Identification of a responsible person in management who has the authority to stop all vessel operations pending correction, oversee vessel compliance activities, and track and verify the correction of non-conformities and deficiencies; and

(6) Identification of objective evidence that supports the completion of all elements of a vessel's drydock and internal structural examinations.

(b) The third-party organization responsible for auditing the TSMS must be notified whenever activities related to credit drydocking or internal structural examinations are to be carried out.

(c) The interval between examinations of each item may not exceed the applicable interval described in § 137.305 of this part.

(d) Prior to commencing work, the owner or managing operator must notify the cognizant Officer in Charge, Marine Inspection (OCMI) of the zone within which activities related to credit drydocking or internal structural surveys are to be carried out.

(e) If the OCMI described in paragraph (d) of this section has reason to believe that an audited program of drydock and internal structural survey is deficient, s/he may:

(1) Require an audit of ongoing drydocking procedures and documentation applicable to the vessel in the presence of a representative of the cognizant OCMI;

(2) Increase the frequency of the audits; or

(3) Require a survey by an approved third party.

(4) Require any specific action within his power and authority deemed appropriate.

(5) For continued deficiencies, remove the vessel and/or owner or managing operator from the TSMS system.

§ 137.320 Vessels holding a valid load line certificate.

(a) A towing vessel with a valid load line certificate issued by a Recognized Classification Society will meet the requirements of this section.

(b) The cognizant OCMI may request copies of all pertinent load line survey documentation to include the last two periodic surveys.

§ 137.325 General conduct of survey for the TSMS option.

(a) When conducting a survey of a towing vessel as required by this subpart, the surveyor must determine that the hull and related structure and components are free of defects, deterioration, damage, or modifications that reduce effectiveness, and that the vessel is suitable for route and service.

(b) The survey must address the items in § 137.330 of this part as applicable, and include:

(1) Access to internal spaces as appropriate;

(2) Visual survey of the external structure of the vessel to confirm that the condition is properly maintained; and

(3) Visual survey to confirm that unapproved modifications were not made to the vessel.

(c) The thoroughness and stringency of the survey will depend upon the condition of the vessel.

(d) The owner or managing operator must notify the cognizant Officer in Charge, Marine Inspection (OCMI) when the condition of the vessel creates an unsafe condition.

(e) The cognizant OCMI may require that the owner or managing operator provide for the attendance of an approved third-party surveyor or auditor to assist with verifying compliance with this subpart.

§ 137.330 Scope of drydock examination.

(a) This regulation applies to all towing vessels covered by this subchapter. The drydock examination must be conducted while the vessel is hauled out of the water or placed in a drydock or slipway. The Coast Guard inspector or surveyor conducting this examination must:

(1) Examine the exterior of the hull, including bottom, sides, headlog, and stern; all appendages for damage, fractures, wastage, pitting, or improper repairs.

(2) Examine each tail shaft for bends, cracks, and damage, including the sleeves or other bearing contact surface(s) on the tail shaft for wear. The tail shaft need not be removed for examination if these items can otherwise be properly evaluated;

(3) Examine rudders for damage; upper and lower bearings for wear; and rudder stock for damage or wear. Rudders need not be removed for examination if these items can be properly evaluated without doing so;

(4) Examine propellers for cracks and damage;

(5) Examine exterior components of the machinery cooling system for leaks, damage, or deterioration;

(6) Open and examine all sea chests, thru-hull fittings, and strainers for damage, deterioration, or fouling; and

(7) On wooden vessels, pull fastenings as required for examination.

(b) An internal structural examination/survey required by this part may be conducted while the vessel is afloat or out of the water. It consists of a complete examination of the vessel's main strength members, including the major internal framing, the hull plating and planking, voids, and ballast, cargo, and fuel oil tanks. Where the internal framing, plating, or planking of the vessel is concealed, sections of the lining, ceiling, or insulation may be removed or the parts otherwise probed or exposed to determine the condition of the hull structure. Fuel oil tanks need not be cleaned out and internally examined if the general condition of the tanks is determined to be satisfactory by external examination.

§ 137.335 Underwater survey in lieu of drydocking.

(a) This section applies to all towing vessels subject to this subchapter. If a Towing Safety Management System (TSMS) is applicable to the vessel, the TSMS may include policies and procedures for employing and documenting an underwater survey in lieu of drydocking (UWILD). A UWILD may be conducted if:

(1) No obvious damage or defects in the hull adversely affecting the seaworthiness of the vessel are present;

(2) The vessel has been operated satisfactorily since the last drydocking;

(3) The vessel is less than 15 years of age;

(4) The vessel has a steel or aluminum hull; and

(5) The vessel is fitted with an effective hull protection system.

(b) The owner or operator must submit an application at least 90 days before the vessel's next required drydock examination. The application must include:

(1) The procedure for carrying out the underwater survey;

(2) The time and place of the underwater survey;

(3) The method used to accurately determine the diver's or remotely operated vehicle (ROV)'s location relative to the hull;

(4) The means for examining all through-hull fittings and appurtenances;

(5) The condition of the vessel, including the anticipated draft of the vessel at the time of the survey;

(6) A description of the hull protection system; and

(7) The name and qualifications of any third party examiner, if used.

(c) If a vessel is 15 years old or older, the Commandant may approve an underwater survey instead of a drydock examination, at alternating intervals. The owner or operator must submit an application to the OCMI at least 90 days before the vessel's next required drydock examination. The owner or operator may follow this option if—

(1) The vessel is qualified under paragraphs (a)(1), (2), (4), and (5) of this section;

(2) The application includes the information described in paragraphs (b)(1) through (7) of this section; and

(3) During the vessel's drydock examination preceding the underwater survey, a complete set of hull gauging was taken which indicated that the vessel was free from appreciable hull deterioration.

(d) After the drydock examination required by paragraph (c)(3) of this section, the OCMI will submit a recommendation for future underwater surveys, the results of the hull gauging, and the results of the Coast Guard's drydock examination to Commandant for review.

PART 138—TOWING SAFETY MANAGEMENT SYSTEMS (TSMS)

Subpart A—General

Sec.

Subpart B—Towing Safety Management System (TSMS)

Subpart C—Documenting Compliance

Subpart D—Audits

Subpart E—Coast Guard or Organizational Oversight and Review

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 138.100 Purpose.

The purpose of this part is to prescribe requirements for owners or managing operators of towing vessels who adopt a Towing Safety Management System (TSMS) to comply with the requirements of this subchapter.

§ 138.105 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 138.110 Incorporation by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the Coast Guard must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal regulations/ibr_locations.html.* Also, it is available for inspection at U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street, SW., Washington, DC 20593–0001, and is available from the sources listed in paragraph (b) of this section.

(b) The material approved for incorporation by reference in this part and the sections affected are:

INTERNATIONAL ORGANIZATION FOR STANDARDIZATION (ISO), 1, CH. DE LA VOIE-CREUSE, CASE POSTALE 56, CH–1211 GENEVA 20, SWITZERLAND

9001–2000, 2000	138.310

§ 138.115 Compliance.

Owners or managing operators of towing vessels must obtain the Towing Safety Management System Certificate issued under § 138.305 of this part no later than [DATE 2 YEARS AFTER EFFECTIVE DATE OF FINAL RULE] if they do not want to be subject to an annual, Coast Guard inspection regime.

Subpart B—Towing Safety Management System (TSMS)

§ 138.200 Safety management.

All towing vessels must be operated in compliance with an owner- or managing operator-implemented Towing Safety Management System or be subject to an annual, Coast Guard inspection regime.

§ 138.205 Purpose of Towing Safety Management System (TSMS).

(a) The purpose of a safety management system is to establish policies, procedures, and required documentation to ensure the owner or managing operator meets its established goals while ensuring continuous compliance with all regulatory requirements. The safety management system must contain a method to ensure all levels of the organization are working within the framework.

(b) A Towing Safety Management System establishes and maintains:

(1) Management policies and procedures that serve as an operational protocol for all levels within management;

(2) Procedures to produce objective evidence that demonstrates compliance with the requirements of this subchapter;

(3) Procedures for an owner or managing operator to self-evaluate that ensure it is following its own policies and procedures and complies with the requirements of this subchapter;

(4) Arrangements for a periodic evaluation by an independent third party to determine how well an owner or managing operator and their towing vessels are complying with their stated policies and procedures, and to verify that those policies and procedures comply with the requirements of this subchapter; and

(5) Procedures for correcting problems identified by management personnel and third parties and facilitating continuous improvement.

§ 138.210 Objectives of Towing Safety Management System (TSMS).

The Towing Safety Management System (TSMS), through policies, procedures, and documentation must:

(a) *Demonstrate management responsibility.* The management must demonstrate that they implemented the policies and procedures as contained in the TSMS and the entire organization is adhering to their safety management program.

(b) *Document management procedures.* A TSMS must describe and document the owner or managing operator's organizational structure, responsibilities, procedures, and resources which ensure quality monitoring.

(c) *Ensure document and data control.* There must be clear identification of what types of documents and data are to be controlled, and who is responsible for controlling activities, including: Approval, issue, distribution, modification, removal of obsolete materials, and other related administrative functions.

(d) *Provide a process and criteria for selection of third parties.* Procedures for selection of third parties must exist that include how third parties are evaluated, including selection criteria.

(e) *Establish a system of recordkeeping.* Records must be maintained to demonstrate effective operation of the TSMS. This should include audit records, nonconformity reports and corrective actions, auditor qualifications, auditor training, and other records as considered necessary.

(f) *Identify and meet training needs.* Documented procedures for identifying training needs and providing training must be established and maintained.

(g) *Ensure adequate resources.* Identify adequate resources and procedures necessary to comply with the TSMS.

§ 138.215 Functional requirements of a Towing Safety Management System (TSMS).

The functional requirements of a Towing Safety Management System (TSMS) include:

(a) Policies and procedures to provide direction for the safe operation of the towing vessels and protection of the environment in compliance with applicable U.S. law, including the Code of Federal Regulations, and, if on an international voyage, applicable international conventions to which the United States is a party;

(b) Defined levels of authority and lines of communication between shoreside and vessel personnel;

(c) Procedures for reporting accidents and non-conformities;

(d) Procedures to prepare for and respond to emergency situations by shoreside and vessel personnel;

(e) Procedures for verification of vessel compliance with this subchapter;

(f) Procedures to manage contracted (vender safety) services.

(g) Procedures for internal auditing of the TSMS, including shoreside and vessels;

(h) Procedures for external audits;

(i) Procedures for management review of internal and external audit reports and correction of non-conformities; and

(j) Procedures to evaluate recommendations made by management personnel.

§ 138.220 Towing Safety Management System (TSMS) elements.

The Towing Safety Management System (TSMS) must include the elements listed in paragraphs (a) through (e) of this section. If an element listed is not applicable to an owner or managing operator, appropriate justification must be documented and is subject to acceptance by the third party.

(a) *Safety management system administration and management organization.* A policy must be in place that outlines the TSMS culture and how management intends to ensure compliance with this subpart. Supporting this policy, the following procedures and documentation must be included:

(1) *Management organization*—(i) *Responsibilities.* The management organization, authority, and responsibilities of individuals.

(ii) *Designated person.* Each owner or managing operator must designate in writing the shoreside person(s) responsible for ensuring the TSMS is implemented and continuously functions throughout management and the fleet, and the shoreside person(s) responsible to ensure that the vessels are properly maintained and in operable condition, including those responsible for emergency assistance to each towing vessel.

(iii) *Master Authority.* Each owner or managing operator must define the scope of the master's authority. The master's authority must provide for the ability to make final determinations on safe operations of the towing vessel. Specifically, it must provide the authority for the master to cease operation if an unsafe condition exists.

(2) *Audit Procedures.* (i) Procedures for conducting internal and external audits, in accordance with §§ 138.310 and 138.315 of this part.

(ii) *Procedures for identifying and correcting non-conformities.* The TSMS must contain procedures for any person working within the management to report non-conformities. The procedures must describe how an initial report should be made and the actions taken to follow up and ensure appropriate resolution.

(b) *Personnel.* Policies must be in place that cover the owner or managing operator's approach to managing its personnel, including, but not limited to, employment, training, and health and safety of personnel. Supporting these polices, the following procedures and documentation must be included:

(1) *Employment procedures.* The TSMS must contain procedures related to the employment of individuals. Procedures must be in place to ensure adequate qualifications of personnel, to include background checks, compliance with drug and alcohol standards, and that personnel are physically and mentally capable to perform required tasks.

(2) *Training of personnel.* The TSMS must contain a policy related to the training of personnel, including:

(i) New hire orientation;

(ii) Duties associated with the execution of the TSMS;

(iii) Execution of operational duties;

(iv) Execution of emergency procedures;

(v) Occupational health;

(vi) Crew safety; and

(vii) Training required by this Subchapter.

(c) *Verification of vessel compliance.* Policies must be in place that cover the owner or managing operator's approach for ensuring vessel compliance, including, but not limited to, policies on survey and maintenance, safety, the environment, security, and emergency preparedness. Supporting these policies, the following procedures and documentation must be included:

(1) *Maintenance and survey.* Procedures outlining the owner or managing operator's survey regime must specify all maintenance, examination, and survey requirements. Applicable documentation must be maintained for all activities for a period of 5 years.

(2) *Safety, environment, and security.* Procedures must be in place to ensure safety of property, the environment, and personnel. This must include procedures to ensure the selection of the appropriate vessel, including adequate maneuverability and horsepower, appropriate rigging and towing gear, proper management of the navigational watch, and compliance with applicable security measures.

(3) All procedures required by this subchapter must be contained within the TSMS.

(d) *Compliance with Subchapter M.* Procedures and documentation must be in place to ensure that each towing vessel complies with the operational, equipment, and personnel requirements of this subchapter.

(e) *Contracted (vendor safety) services.* Procedures must be in place to ensure the safety, effective management, and compliance with applicable regulations for contracted vessel towing services, including:

(1) Procedures to evaluate personnel qualifications;

(2) Procedures to evaluate adequacy of vessel capability, condition, and compliance with applicable regulations;

(3) Compatibility of Safety Management Systems; and

(4) Procedures to maintain objective evidence, as required by both organizations' safety management systems.

§ 138.225 Existing safety management systems.

(a) A safety management system which is fully compliant with the International Safety Management Code requirements of 33 CFR part 96 will be deemed in compliance with these requirements.

(b) Other safety management systems may be considered for acceptance as meeting the Towing Safety Management System (TSMS) requirements of this part. The Coast Guard may:

(1) Accept such system in full;

(2) Require modifications to the system as a condition of acceptance; or

(3) Reject the system.

(c) An owner or managing operator wishing to meet this section must submit documentation based on the initial audit and one full audit cycle of at least 3 years.

(d) The Coast Guard may elect to inspect equipment and records, including:

(1) Contents of the TSMS;

(2) Objective evidence of internal and external audits;

(3) Objective evidence that non-conformities were identified and corrected; and

(4) Objective evidence of vessel compliance with applicable regulations.

Subpart C—Documenting Compliance

§ 138.300 General.

(a) The owner and managing operator must have documentation that demonstrates compliance with the provisions of the Towing Safety Management System (TSMS) in order for any of its towing vessels to be eligible for a Certificate of Inspection.

(b) The owner or managing operator will be issued a TSMS Certificate when it is deemed in compliance with the TSMS requirements.

§ 138.305 Towing Safety Management System (TSMS) Certificate.

(a) A Towing Safety Management System (TSMS) Certificate is obtained through an approved third party.

(b) A TSMS Certificate is valid for 5 years from the date of issue, unless suspended, revoked or rescinded as provided in § 138.305(d) and (e).

(c) The TSMS Certificate must include a list of the owner or managing operator's vessels found in compliance with the TSMS.

(d) A TSMS Certificate may be suspended or revoked by the Coast Guard at any time for non-compliance with the requirements of this part.

(e) The third party that issued the TSMS Certificate may rescind the certificate for non-compliance with the requirements of this part.

(f) A copy of the TSMS Certificate must be maintained on each towing vessel that has been issued a TSMS and on file at the owner or managing operator's shoreside office.

§ 138.310 Internal Audits for Towing Safety Management System (TSMS) Certificate.

(a) Internal management audits must be conducted annually, within 3 months of the anniversary issuance of the Towing Safety Management System (TSMS) Certificate, to ensure the owner or managing operator is effectively implementing all elements of their TSMS.

(b) The internal management audit must ensure that management has implemented the TSMS throughout all levels of the organization, including audits of all the owner or managing operator's towing vessels to ensure implementation at the operational level.

(c) The results of internal audits must be documented and maintained for a period of 5 years and made available to the Coast Guard upon request.

(d) Internal auditors:

(1) Must have knowledge of the management, its safety management system, and the standards contained in this subchapter;

(2) Must have completed an International Organization for Standardization (ISO) 9001–2000 (incorporated by reference in § 138.105 of this subchapter) internal auditor/assessor course or Coast Guard recognized equivalent;

(3) May not be the designated person, or any other person, within the organization that is responsible for development or implementation of the TSMS; and

(4) Must be independent of the procedures being audited.

§ 138.315 External Audits for Towing Safety Management System (TSMS) Certificate.

External audits for obtaining and renewing a Towing Safety Management System (TSMS) Certificate are conducted by an approved third party auditor and must include both management and vessels as follows:

(a) *Management audits.* (1) Prior to the issuance of an owner or managing operator's initial and subsequent renewals of a TSMS Certificate, an external management audit must be conducted by an approved third party auditor.

(2) A mid-period external management audit must be conducted between the 27th and 33rd month of the certificate's period of validity.

(b) *Vessel audits.* (1) An external audit of all vessels subject to the owner or managing operator's TSMS must be conducted prior to the issuance of the initial TSMS Certificate.

(2) An external audit of all vessels must be conducted during the 5-year period of validity of the TSMS certificate. The vessels must be selected randomly and distributed as evenly as possible.

(c) *Audit results.* The results of the external audit must be documented and maintained for a period of 5 years and made available to the Coast Guard or the external auditor upon request.

Subpart D—Audits

§ 138.400 General.

All safety management systems are subject to internal and external audits to assess the management and vessel compliance with the Towing Safety Management System and the vessel standards requirements of this subchapter.

§ 138.405 Conduct of internal audits.

(a) Internal audits are conducted by, or on behalf of, the management and may be performed by a designated employee or by contracted individual(s) who conduct the audit as if an employee of the owner or managing operator.

(b) Internal audits are not necessarily conducted as one event; they can be taken in segments over time.

(c) Internal audits must be of sufficient depth and breadth to ensure the owner or managing operator established adequate procedures and documentation to comply with the Towing Safety Management System (TSMS) requirements of this part, that the TSMS was implemented throughout all levels of the organization, and that the owner or managing operator's vessels comply with this subchapter and the TSMS.

(e) The auditor must have the authority to examine documentation, question personnel, examine vessel equipment, witness system testing, and observe personnel training as necessary to verify TSMS effectiveness.

§ 138.410 Conduct of external audits.

(a) External audits must be conducted by an approved third party auditor and cover all elements of the Towing Safety Management System (TSMS) requirements of Subchapter M of this chapter, but may be conducted on a sampling basis of each of those TSMS elements.

(b) External audits must be of sufficient depth and breadth to ensure the owner or operating manager effectively implemented its TSMS throughout all levels of the organization, including onboard its vessels.

(c) The auditor must be provided access to examine any requested documentation, question personnel, examine vessel equipment, witness system testing, and observe personnel training, as necessary to verify TSMS effectiveness.

(d) The auditor may broaden the scope of the audit if:

(1) The TSMS is incomplete or not effectively implemented;

(2) Conditions found are not consistent with the records; or

(3) Unsafe conditions are identified.

(e) The auditor may verify compliance with vessel standards and TSMS requirements through a review of objective evidence such as checklists, invoices, and reports, and may conduct a visual ''sampling'' onboard the vessels to determine whether or not the conditions onboard the vessel are consistent with the records reviewed.

(f) All samples must be statistically valid.

Subpart E—Coast Guard or Organizational Oversight and Review

§ 138.500 Notification prior to audit.

(a) The owner or managing operator of a towing vessel must notify the Coast Guard prior to conducting a third-party audit.

(b) The Coast Guard may require that a Coast Guard representative accompany the auditor during part, or all, of an external audit.

(c) The Coast Guard may conduct an audit of the owner or managing operator or its towing vessels.

§ 138.505 Submittal of audit results.

The results of any external audit of the owner or managing operator's compliance with § 138.210 of this part and each of their towing vessels audits must be submitted to the Coast Guard.

§ 138.510 Required attendance.

(a) The Coast Guard may require a third-party's attendance at the vessel or the office of the owner or managing operator if there is evidence that a Towing Safety Management System (TSMS), for which a TSMS Certificate was issued, is not in compliance with the provision of this part.

(b) The third party and the owner or managing operator may be required to explain or otherwise demonstrate areas of the TSMS.

(c) The Coast Guard will not bear any of the costs for a third party's attendance at the vessel or the office of the owner or managing operator when complying with this provision.

PART 139—THIRD-PARTY ORGANIZATIONS

Sec.

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

§ 139.100 Purpose.

This part states the requirements applicable to approved third-party organizations that conduct audits and surveys for towing vessels as required by this subchapter.

§ 139.105 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 139.110 Organizations not subject to further approval.

(a) A recognized classification society, as defined by 46 CFR 8.100, meets the requirements of an approved third-party organization for the purposes of this part.

(b) Recognized classification societies must ensure that employees providing services under this part hold proper qualifications for the particular type of service being performed.

§ 139.112 Incorporation by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the Coast Guard must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.* Also, it is available for inspection at U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street, SW., Washington, DC 20593–0001, and is available from the sources listed in paragraph (b) of this section.

(b) The material approved for incorporation by reference in this part and the sections affected are:

American National Standards Institute (ANSI), 1819 L Street, NW., Suite 600, Washington, DC 20036

ANSI/ASQC Q9001–2000, 2000 139.120

International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland

ISO 9001–2000, 2000 139.130

§ 139.115 General.

(a) The Coast Guard approves third-party organizations to carry out functions related to ensuring that towing vessels comply with provisions of this subchapter. Organizations may be approved to:

(1) Conduct audits of a Towing Safety Management System (TSMS), and the vessels to which the TSMS applies, to verify compliance with the applicable provisions of this subchapter.

(2) Issue TSMS Certificates to the owner or managing operator who is in compliance with part 138 of this subchapter.

(3) Conduct surveys of towing vessels to verify compliance with the applicable provisions of this subchapter.

(4) Issue survey reports detailing the results of surveys, carried out in compliance with part 137 of this subchapter.

(b) The Coast Guard will approve third-party organizations that:

(1) Are independent of the owner or managing operator and vessels that they audit or survey;

(2) Operate within a quality management system acceptable to the Coast Guard;

(3) Ensure that the organization's auditors and surveyors are qualified and maintain continued competence; and

(4) Demonstrate the ability to carry out the responsibilities of approval.

(c) The Coast Guard may designate an organization to be an approved third party when that organization provides objective evidence that its program meets the requirements of this subchapter.

(d) A list of approved third-party organizations will be maintained by the Coast Guard, and made available upon request.

§ 139.120 Application for approval as a third-party organization.

An organization, which may include a business entity or an association, desiring to be approved as a third-party organization under this part must submit a written request to Coast Guard, 2100 Second Street, SW., Washington, DC 20593–0001. The organization must provide the following information:

(a) A description of the organization, including the ownership, structure, and organizational components.

(b) A general description of the clients being served or intended to be served.

(c) A description of the types of work performed by the organization or by the principals of the organization in the past, noting the amount and extent of such work performed within the previous 3 years.

(d) Objective evidence of an internal quality system based on American National Standards Institute/American Society of Quality Control Q9001–2000 (ANSI) (incorporated by reference in § 138.105 of this chapter) or an equivalent quality standard.

(e) Organization procedures and supporting documentation describe processes used to perform the audit and records to show system effectiveness.

(f) Copies of checklists, forms, or other tools to be used as guides or for recording the results of audits and/or surveys.

(g) Organization procedures for appeals and grievances.

(h) The organization's code of ethics applicable to the organization and its auditors and/or surveyors.

(i) A list of the organization's auditors and/or surveyors who meet the requirements of § 139.130 of this subchapter. This list must include the experience, background, and qualifications for each auditor and/or surveyor.

(j) A description of the organization's means of assuring continued competence of its personnel.

(k) The organization's procedures for terminating or removing auditors and/or surveyors.

(l) A description of the organization's apprentice or associate program for auditors and/or surveyors.

(m) A statement that the Coast Guard may inspect the organization's facilities and records and may accompany auditors and/or surveyors in the performance of duties related to the requested approval.

(n) Disclosure of any potential conflicts of interest.

(o) A statement that the organization, its managers, and employees engaged in audits and/or surveys are not, and will not be involved in any activities which could result in a conflict of interest or otherwise limit the independent judgment of the auditor and/or surveyor or organization.

(p) Any additional information that the applicant deems pertinent.

§ 139.125 Approval of third-party organizations.

(a) The Coast Guard will review the request and notify the organization in writing whether the requested approval is granted.

(b) If a request for approval is denied, the Coast Guard will inform the organization of the reasons for the denial and will describe what corrections are required for an approval to be granted.

(c) An approval for a third-party organization that meets the requirements of this part will expire:

(1) Five years after the last day of the month in which it is granted;

(2) When the third-party organization gives notice that it will no longer offer towing vessel audit and/or survey services;

(3) When revoked by the Coast Guard; in accordance with § 139.150 or;

(4) On the date of a change in ownership of the third-party organization for which approval was granted.

§ 139.130 Qualifications of auditors and surveyors.

(a) A prospective auditor must demonstrate the skills and experience necessary to assess compliance with all requirements of subchapter M of this chapter.

(b) Auditors must meet the following qualifications:

(1) High school diploma or equivalent;

(2) Four years of experience working on towing vessels or other relevant marine experience such as Coast Guard marine inspector, military personnel with relevant maritime experience, or marine surveyor;

(3) Successful completion of an International Organization for Standardization (ISO) 9001–2000 (incorporated by reference in § 139.112 of this part) lead auditor/assessor course or Coast Guard recognized equivalent;

(4) Successful completion of a required training course for the auditing of a Towing Safety Management System; and

(5) Audit experience, as demonstrated by one of the following:

(i) Documented experience in auditing the ISM Code or the American Waterways Operators Responsible Carrier Program, consisting of at least two management audits and six vessel audits within the past 5 years; or

(ii) Successful completion of a required auditor apprenticeship, consisting of at least one management audit and three vessel audits under the direction of a lead auditor.

(c) Surveyors must meet the following qualifications:

(1) High school diploma or equivalent; and

(2) Four years of experience working on towing vessels as master, mate (pilot), or engineer; or

(3) Other relevant marine experience such as Coast Guard marine inspector, military personnel with relevant maritime experience, marine surveyor, experience on vessels of similar operating and physical characteristics; or

(4) Marine surveyor accredited by the National Association of Marine Surveyors, Society of Accredited Marine Surveyors, or other accreditation acceptable to the Coast Guard.

§ 139.135 Addition and removal of auditors and surveyors.

(a) An approved third-party organization must maintain a list of current and former auditors and surveyors.

(b) To add an auditor or surveyor, the organization must submit the experience, background and qualifications to the Coast Guard for approval.

(c) The Coast Guard must be notified when an auditor or surveyor is removed from employment.

§ 139.140 Renewal of third-party organization approval.

(a) To renew an approval, a third-party organization must submit a written request to the address listed in § 139.120 of this part.

(b) For the request to be approved, the Coast Guard must be satisfied that the applicant continues to fully meet approval criteria.

(c) The Coast Guard may request any additional information necessary to properly evaluate the request.

§ 139.145 Suspension of approval.

(a) The Coast Guard may suspend the approval of a third-party organization approved under this part whenever the Coast Guard determines that the approved third-party organization does not comply with the provisions of this part. The Coast Guard must:

(1) Notify the approved third-party organization in writing of the intention to suspend the approval;

(2) Provide the details of the third-party organization's failure to comply with this part; and

(3) Advise the third-party organization of the time period, not to exceed 60 days, within which the third-party organization must correct its failure to comply with this part. If the third-party organization fails to correct its failure to comply with this part within the time period allowed, the approval will be suspended.

(b) The Coast Guard may partially suspend the approval of a third-party organization. This may include suspension of an individual auditor or surveyor or suspension of the authority of the third-party organization to carry out specific duties whenever the Coast Guard determines that the provisions of this part are not complied with. The Coast Guard must:

(1) Notify the approved third-party organization in writing of its intention to partially suspend the approval;

(2) Provide the details of the failure of the auditor or surveyor to comply with this part; and

(3) Advise the third-party organization of the time period, not to exceed 60 days, within which the third-party organization must ensure that the auditor or surveyor corrects his/her failure to comply with this part. If the third-party organization fails to correct the failure of the auditor or surveyor to comply with this part within the time period allowed, the approval will be partially suspended with respect to such auditor or surveyor.

§ 139.150 Revocation of approval.

The Coast Guard may revoke the approval of a third-party organization if the organization has demonstrated a pattern or history of:

(a) Failure to comply with this part;

(b) Substantial deviations from the terms of the approval granted under this part; or

(c) Failures, including ethics, conflicts of interest or performance, that indicate to the Coast Guard that the third-party organization is no longer capable of carrying out its duties as an approved third-party organization.

§ 139.155 Appeals of suspension or revocation of approval.

Anyone directly affected by a decision to suspend or revoke an approval granted under this part may appeal the decision to the Coast Guard in accordance with the provisions of 46 CFR part 1.

§ 139.160 Coast Guard oversight activities.

At any time the Coast Guard may:

(a) Inspect a third-party organization's records;

(b) Conduct interviews of auditors or surveyors to aid in the evaluation of the organization;

(c) Assign personnel to observe or participate in audits or surveys;

(d) Observe audits or surveys conducted by the third-party organization;

(e) Request that the owner or managing operator make available, a copy of the Towing Safety Management System (TSMS); or

(f) Require a revision of the TSMS if it is determined that requirements of this subchapter are not met.

(g) Require a replacement for a third-party auditor for noncompliance or poor performance.

§ 139.165 Documentation.

(a) Each approved third-party organization must retain the results of each survey or audit conducted under its approval, including:

(1) The names of the auditors and/or surveyors;

(2) The results of each audit or survey conducted;

(3) Documentation showing continuing actions relative to an audit or survey, such as resolution of deficiencies and non-conformities; and

(4) Results of audits of the third party organization.

(b) Records required by this part must be retained for a period of 5 years.

§ 139.170 Required attendance.

(a) The Coast Guard may require a third-party organization's attendance at a towing vessel or the offices of the owner or managing operator in the following circumstances:

(1) When there is evidence that the Towing Safety Management System (TSMS) for which a TSMS Certificate was issued is not in compliance with the provisions of part 138 of this subchapter.

(2) When there is objective evidence that a towing vessel that was surveyed by a third party is not in compliance with the requirements of this subchapter.

(b) The Coast Guard will not bear any costs for a third party organization's attendance at the vessel or the offices of the owner or managing operator when complying with this provision.

PART 140—OPERATIONS

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 140.100 Purpose.

This part contains the health, safety, and operational requirements for towing vessels and the crewmembers serving onboard them.

§ 140.105 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

Subpart B—General Operational Safety

§ 140.200 Towing Safety Management System (TSMS).

If a Towing Safety Management System (TSMS) is applicable to the vessel, the TSMS must:

(a) Include policies and procedures to ensure compliance with this part; and

(b) Provide objective evidence that documents compliance with the TSMS.

§ 140.205 General vessel operation.

(a) A vessel must be operated in accordance with applicable laws and regulations and in such a manner as to afford protection against hazards to life, property, and the environment.

(b) Towing vessels with a TSMS must be operated in accordance with the TSMS applicable to the vessel.

(c) Vessels must be manned in accordance with the Certificate of Inspection (COI). Manning requirements are contained in part 15 of this chapter.

(d) Each crewmember that is required to hold a Merchant Mariner Credential (MMC) must have the credential onboard and available for examination at all times when the vessel is operating.

(e) All individuals who are not required to hold an MMC permitted onboard the vessel must have and present on request a valid personal identification that meets the requirements set forth in 33 CFR 101.105.

§ 140.210 Responsibilities of the master and crew.

(a) The safety of the towing vessel is the responsibility of the master and includes:

(1) Adherence to the provisions of the Certificate of Inspection (COI);

(2) Compliance with the applicable provisions of this subchapter;

(3) Compliance with Towing Safety Management System (TSMS) applicable to the vessel, if one is applicable; and

(4) Supervision of all persons onboard in carrying out their assigned duties.

(b) If the master believes it is unsafe for the vessel to proceed, that an operation endangers the vessel or crew, or that an unsafe condition exists, the master must ensure that adequate corrective action is taken and must not proceed until it is safe to do so.

(c) Nothing in this subpart shall be construed in a manner which limits the master or mate (pilot), at his or her own responsibility, from diverting from the route prescribed in the COI or taking such steps as he deems necessary and prudent to assist vessels in distress or for other emergency conditions.

(d) It is the responsibility of the crew to:

(1) Adhere to the provisions of the COI;

(2) Comply with the applicable provisions of this subchapter;

(3) Comply with the TSMS applicable to the vessel, if the vessel has a TSMS;

(4) Ensure that the master is made aware of all known aspects of the condition of the vessel, including:

(i) Those vessels being pushed, pulled, or hauled alongside; and

(ii) Equipment and other accessories used for pushing, pulling, or hauling along side other vessels.

(5) Report unsafe conditions to the master and take the most effective action to prevent accidents.

Subpart C—[Reserved]

Subpart D—Crew Safety

§ 140.400 Personnel records.

(a) The master of each towing vessel must keep an accurate list of crewmembers and their positions.

(b) The master must maintain a list of individuals carried onboard the vessel.

(c) The date and time that a navigation watchstander, including master, mate (pilot), and lookout assumes a watch and is relieved of a watch must be recorded in the towing vessel record (TVR) or the official logbook, or in accordance with the TSMS applicable to the vessel. If an engineering watch is maintained, comparable records documenting the engineering watch are required.

§ 140.405 Emergency duties and duty stations.

(a) Any towing vessel with alternating watches (shift work) or overnight accommodations must identify the duties and duty stations of each person onboard during an emergency, including:

(1) Responding to fires and flooding;

(2) Responding to emergencies that necessitate abandoning the vessel;

(3) Launching survival craft and rescue boats;

(4) Taking action during heavy weather;

(5) Taking action in the event of a person overboard;

(6) Taking action relative to the tow;

(7) Taking action in the event of failure of propulsion, steering, or control system;

(8) Managing individuals onboard who are not crewmembers;

(9) Managing any other event or condition which poses a threat to life, or property; and

(10) Responding to other special duties essential to addressing emergencies as determined by the TSMS applicable to the vessel, if a TSMS is used.

(b) The emergency duties and duty stations required by this section must be posted at the operating station and in a conspicuous location in a space commonly visited by crewmembers. If posting is impractical, such as in an open boat, they may be kept onboard in a location readily available to the crew.

§ 140.410 Safety orientation.

(a) Upon initial employment, or prior to getting underway for the first time on a particular towing vessel, each crewmember must receive a safety orientation on the following subjects:

(1) His or her duties in an emergency;

(2) The location, operation, and use of lifesaving equipment;

(3) Prevention of falls overboard;

(4) Personal safety measures;

(5) The location, operation, and use of Personal Protective Equipment;

(6) Emergency egress procedures;

(7) The use and operation of watertight and weathertight closures;

(8) Responsibilities to provide assistance to individuals that are not crewmembers;

(9) How to respond to emergencies relative to the tow; and

(10) Awareness of, and expected response to, any other hazards inherent to the operation of the towing vessel which may pose a threat to life, property, or the environment.

(b) The safety orientation provided to crewmembers who received a safety orientation on another vessel may be modified to cover only those areas unique to the new vessel on which service will occur.

(c) Safety orientations and other crew training must be documented in the towing vessel record (TVR), official logbook, or in accordance with the TSMS applicable to the vessel. The entry must include the following information:

(1) Date of the safety orientation or training;

(2) General description of the safety orientation or training topics;

(3) Name of individual(s) providing the orientation or training; and

(4) Name(s) of the individual(s) receiving the safety orientation or training.

§ 140.415 Orientation for individuals that are not crewmembers.

(a) Individuals, that are not crewmembers, onboard a towing vessel must receive a safety orientation prior to getting underway or as soon as practicable thereafter to include:

(1) The location, operation, and use of lifesaving equipment;

(2) Emergency procedures;

(3) Methods to notify crewmembers in the event of an emergency; and

(4) Prevention of falls overboard.

(b) [Reserved]

§ 140.420 Emergency drills and training.

(a) The master of a towing vessel must ensure that drills are conducted and instructions are given to ensure that all crewmembers are capable of performing the duties expected of them during emergencies. This includes abandoning the vessel, recovering persons from the water, responding to onboard fires and flooding, or responding to other threats to life, property, or the environment.

(b) Each drill must, as far as practicable, be conducted as if there was an actual emergency.

(c) Unless otherwise stated, each crewmember must receive the training required by this section annually.

(d) The following training or drills are required:

(1) Safety orientation, as required by § 140.410 of this part;

(2) Emergency drills and training, as required by this section;

(3) Training on response to fires, as required by § 142.245 of this subchapter;

(4) Training on launching of a skiff, if listed as an item of emergency equipment to abandon ship or man overboard recovery;

(5) If installed, training on the use of davit-launched liferafts; and

(6) If installed, training on how each rescue boat must be launched, with its assigned crew aboard, and maneuvered in the water as if during an actual man overboard situation.

(e) *Alternative forms of instruction.* (1) Training as required by this part may be conducted by viewing electronically or digitally formatted training materials followed by a discussion led by someone familiar with the subject matter. This instruction may occur either onboard or off the vessel.

(2) Training may be performed in accordance with the TSMS applicable to the vessel, provided that it meets the minimum requirements of this section.

(f) *Participation in drills and training.* As far as practicable, drills must take place onboard the vessel. They must include:

(1) Participation by all crewmembers; and

(2) Actual use of, or simulating the use of, emergency equipment.

(g) *Recording of drills and training.* Drills and training must be recorded in the towing vessel record or official logbook, or in accordance with the TSMS applicable to the vessel. The record must include the date of the drill and training, a description of the drill scenario and training topics, and the personnel involved.

§ 140.425 Fall overboard protection.

(a) The owner or managing operator of a towing vessel must establish procedures to address fall overboard prevention and recovery of persons in the water, including, but not limited to:

(1) Personal protective equipment;

(2) Safely working on the tow;

(3) Safety while line handling;

(4) Safely moving between the vessel and a tow, pier, structure, or other vessel; and

(5) Use of retrieval equipment.

(b) The owner, managing operator, and master must ensure that all persons onboard comply with the policies and procedures in this section.

§ 140.430 Wearing of work vests.

Personnel dispatched from the vessel or that are working in an area on the exterior of the vessel without rails and guards must wear a lifejacket meeting requirements in 46 CFR 141.340, an immersion suit meeting requirements in 46 CFR 141.350, or a work vest approved by the Commandant under 46 CFR subpart 160.053. When worn at night, the work vest must be equipped with a light that meets the requirements of 46 CFR 141.340(c)(a). Work vests may not be substituted for the lifejackets required by 46 CFR part 141.

(b) Each storage container containing a work vest must be marked ''WORK VEST.''

§ 140.435 First aid equipment.

(a) Each towing vessel must be equipped with an industrial type first aid cabinet or kit, appropriate to the size of the crew and operating conditions. Each towing vessel operating on oceans, coastwise, or Great Lakes routes must have a means to take blood pressure readings, splint broken bones, and apply large bandages for serious wounds.

(b) Each towing vessel with alternating watches (shift work) and overnight accommodations must be provided with an Automatic External Defibrillator (AED).

(c) At least two crewmembers must be trained in the use of an AED carried onboard.

Subpart E—Safety and Health

§ 140.500 General.

(a) No later than 3 years after the effective date of a final rule, the owner or managing operator must implement a health and safety plan. The plan must include recordkeeping procedures. Records must document compliance with this part.

(b) The owner, managing operator, and master must ensure that all persons onboard a towing vessel comply with the health and safety plan.

§ 140.505 General health and safety requirements.

(a) The owner or managing operator must implement procedures for reporting unsafe conditions and must have records of the activities conducted under this section.

(b) All vessel equipment must be used in accordance with the manufacturer's recommended practice and in a manner that minimizes risk of injury or death. This includes machinery, deck machinery, towing gear, ladders, embarkation devices, cranes, portable tools, and safety equipment.

(c) All machinery and equipment that is not in proper working order (including missing or malfunctioning guards or safety devices) must be removed; made safe through marking, tagging, or covering; or otherwise made unusable.

(d) Personal Protective Equipment (PPE)—(1) Appropriate PPE must be made available and on hand for all personnel engaged in an activity that requires the use of PPE.

(2) PPE must be suitable for the vessel's intended service; meet the standards of 29 CFR 1910 subpart I; and be used, cleaned, maintained, and repaired in accordance with manufacturer's requirements.

(3) All individuals must wear PPE appropriate to the activity being performed.

(4) All personnel engaged in an activity must be trained in the proper use, limitations, and care of the PPE specified by this subpart.

(e) The vessel, including crew's quarters and the galley, must be kept in a sanitary condition.

§ 140.510 Identification and mitigation of health and safety hazards.

(a) The owner or managing operator must implement procedures to identify and mitigate health and safety hazards, including but not limited to the following hazards:

(1) Tools and equipment, including deck machinery, rigging, welding and cutting, hand tools, ladders, and abrasive wheel machinery found onboard the vessel;

(2) Slips, trips, and falls;

(3) Working aloft;

(4) Hazardous materials;

(5) Confined space entry;

(6) Blood-borne pathogens and other biological hazards;

(7) Electrical;

(8) Noise;

(9) Falls overboard;

(10) Vessel embarkation and disembarkation (including pilot transfers);

(11) Towing gear, including winches, capstans, wires, hawsers and other related equipment;

(12) Personal hygiene; and

(13) Sanitation and safe food handling.

(b) As far as practicable, the owner or managing operator must implement other types of safety control measures before relying on Personal Protective Equipment. These controls may include administrative, engineering, source modification, substitution, process change or controls, isolation, ventilation, or other controls.

§ 140.515 Training requirements.

(a) All crewmembers must be provided with health and safety information and training that includes:

(1) Content and procedures of the owner or managing operator's health and safety plan;

(2) Procedures for reporting unsafe conditions;

(3) Proper selection and use of Personal Protective Equipment (PPE) appropriate to the vessel operation;

(4) Safe use of equipment including deck machinery, rigging, welding and cutting, hand tools, ladders, and abrasive wheel machinery found onboard the vessel;

(5) Hazard communication and cargo knowledge;

(6) Safe use and storage of hazardous materials and chemicals;

(7) Confined space entry;

(8) Respiratory protection;

(9) Lockout/Tagout procedures;

(b) Individuals, other than crewmembers, must be provided with sufficient information or training on hazards relevant to their potential exposure on or around the vessel.

(c) Crewmember training required by this section must be conducted as soon as practicable, but not later than 5 days after employment.

(d) Refresher training must be repeated annually and may be conducted over time in modules covering specific topics. Refresher training may be less comprehensive, provided that the information presented is sufficient to provide employees with continued understanding of work place hazards. The refresher training of persons subject to this subpart must include the information and training prescribed in § 140.515 of this section.

(e) The owner, managing operator, or master must determine the appropriate training and information to provide to each individual permitted on the vessel who is not a crewmember, relative to the expected risk exposure of the individual.

(f) All training required in this section must be documented in owner or managing operator records.

§ 140.520 Personnel hazard exposure and medical records.

(a) The owner or managing operator must:

(1) Maintain medical records for each employee for at least 6 years following employment;

(2) Ensure that access is provided in a reasonable time, place, and manner, whenever an employee, or a person designated in writing to represent the employee, requests access to a record. If the owner or managing operator cannot reasonably provide access to the record within 15 working days, the owner or managing operator must apprise the employee or designated representative of the reason for the delay and the earliest date when the record can be made available.

(b) Whenever an employee requests access to his or her employee medical records, and a physician representing the owner or managing operator believes that direct employee access to information contained in the records regarding a specific diagnosis of a terminal illness or a psychiatric condition could be detrimental to the employee's health, the owner or managing operator may inform the employee that access will be provided only to a designated representative of the employee having specific written consent, and may deny the employee's request for direct access to this information only. Where a designated representative with specific written consent requests access to information so withheld, the owner or managing operator must ensure the access of the designated representative to this information, even when it is known that the designated representative will give the information to the employee.

Subpart F—Vessel Operational Safety

§ 140.600 Applicability.

This subpart applies to all towing vessels unless otherwise specified. Certain vessels remain subject to the navigation safety regulations in 33 CFR part 164.

§ 140.605 Vessel stability.

(a) A towing vessel with a stability letter must be maintained and operated in accordance with its stability letter.

(b) A towing vessel without a stability letter must be maintained and operated so the watertight integrity and stability of the vessel is not compromised.

(c) Prior to getting underway, and at all other times necessary to ensure the safety of the vessel, the master must determine that the vessel complies with all applicable stability requirements in the vessel's trim and stability book, stability letter, COI, and Load Line Certificate. The vessel will not get underway until the master determines that the vessel complies with these requirements.

§ 140.610 Hatches and other openings.

(a) All towing vessels must be operated in a manner that minimizes the risk of down-flooding and progressive flooding.

(b) The master must ensure that all watertight and weathertight hatches, doors, and other openings function properly.

(c) Hatches and openings of the hull and deck must be kept tightly closed except:

(1) When access is needed through the opening for transit;

(2) When operating on rivers with a tow, if the master determines the safety of the vessel is not compromised; or

(3) When operating on lakes, bays, and sounds, without a tow during calm weather, and only if the master determines that the safety of the vessel is not compromised.

(d) Where installed, all watertight doors in watertight bulkheads must be closed during the operation of the vessel, unless they are being used for transit between compartments; and

(e) When downstreaming, all exterior openings at the main deck level must be closed.

§ 140.615 Tests and inspections.

(a) This section applies to a towing vessel not subject to 33 CFR 164.80.

(b) Prior to getting underway, the master of the vessel must examine and test the steering gear, signaling whistle, propulsion control, towing gear, navigation lights, navigation equipment, and communication systems of the vessel. This examination and testing does not need to be conducted more than once in any 24-hour period.

(c) The results of the inspection must be recorded in the towing vessel record or official logbook, or in accordance with the TSMS applicable to the vessel.

§ 140.620 Navigational safety equipment.

(a) This section applies to a towing vessel not subject to the requirements of 33 CFR 164.82.

(b) The owner, managing operator, or master of each towing vessel must maintain the required navigational-safety equipment in a fully-functioning, operational condition.

(c) Navigational safety equipment that fails during a voyage must be repaired at the earliest practicable time. The owner, managing operator, or master must consider the state of the equipment (along with such factors as weather, visibility, traffic, and the dictates of good seamanship) when deciding whether it is safe for the vessel to proceed.

(d) The failure and subsequent repair or replacement of navigational-safety equipment must be recorded. The record must be made in the official log, towing vessel record, or in accordance with the Towing Safety Management System applicable to the vessel.

§ 140.625 Navigation underway.

(a) This section applies to all towing vessels. Certain towing vessels are also subject to the requirements of 33 CFR 164.78.

(b) At all times, the movement of a towing vessel and its tow must be under the direction and control of a master or mate (pilot) properly licensed under subchapter B of this chapter.

(c) The master or mate (pilot) must ensure that the towing vessel and its tow are operated in a manner that does not pose a threat to life, property, or the environment. Special attention should be paid to:

(1) The velocity and direction of currents in the area being transited;

(2) Tidal state;

(3) Prevailing visibility and weather conditions;

(4) Density of marine traffic;

(5) Potential damage caused by the vessel's own wake or that of its tow;

(6) The danger of each closing visual or radar contact;

(7) Water depth or river stage upon the route and at mooring location;

(8) Air draft relative to bridges and overhead obstructions;

(9) Bridge transits;

(10) Lock transits;

(11) Other navigation hazards such as logs, wrecks or other obstructions in the water;

(12) Handling characteristics of the vessel and tow; and

(13) Magnetic variation and deviation errors of the compass, if installed.

§ 140.630 Lookout.

(a) Throughout the trip or voyage the master and mate (pilot) must assess the requirement for a lookout. A lookout should be added when necessary to:

(1) Maintain a state of vigilance with regard to any significant change in the operational environment;

(2) Appraise the situation and the risk of collision/allision;

(3) Anticipate stranding and other dangers to navigation; and

(4) Detect any other potential hazards to safe navigation.

(b) In determining the requirement for a lookout, the person in charge of the navigation watch must take full account of relevant factors including, but not limited to: State of weather, visibility, traffic density, proximity of dangers to navigation, and the attention necessary when navigating in areas of increased vessel traffic.

§ 140.635 Navigation watch assessment.

(a) This section applies to all towing vessels. Additionally, some vessels remain subject to the requirements of 33 CFR 164.80.

(b) Prior to getting underway or assuming a navigation watch, the person in charge of the navigation watch must conduct a navigation assessment for the intended route. The navigation assessment shall be used to assess operational risks, maintain situational awareness, and anticipate and manage workload demands. The assessment must consider the following factors:

(1) Compliance with applicable provisions of the Towing Safety Management System applicable to the towing vessel, if the vessel has a TSMS;

(2) Waterway conditions, including anticipated current direction and speed, water depth, vessel traffic, and information contained in relevant notice(s) to mariners;

(3) Existing and forecasted weather for the intended route;

(4) Maneuvering characteristics of the towing vessel and tow, taking into account tow configuration, horsepower, and any auxiliary steering units and assist vessels;

(5) Potential waterway obstacles such as bridges, dams and locks, wrecks and other obstructions, reported shoaling, and a determination as to whether adequate air-draft clearance, under-keel clearance, and horizontal clearance exist;

(6) Anticipated workload caused by the nature of the towing vessel's functions, immediate operating requirements, and anticipated maneuvers;

(7) Any other relevant standard, procedure or guidance relating to watchkeeping arrangements and fitness for duty;

(8) The knowledge and qualifications of crewmembers who are assigned as members on watch;

(9) The experience and familiarity of crewmembers with the towing vessel's equipment, procedures, and maneuvering capability;

(10) The activities taking place onboard the towing vessel and the tow;

(11) Availability of assistance to be summoned immediately to the pilothouse when necessary;

(12) The operational status of pilothouse instrumentation and controls, including alarm systems;

(13) Size of the towing vessel and tow and the field of vision available from the operating station;

(14) The configuration of the pilothouse, to the extent that such configuration may inhibit a member of the watch from detecting by sight or hearing any external development; and

(15) Any special conditions not covered above that impact the safety of navigation.

(c) At each change of the navigation watch, the oncoming watch must ensure that the navigation risk assessment is current and valid.

(d) The assessment must be updated as necessary, such as when changes occur to the tow configuration, route, weather or other routine conditions.

(e) When an assessment is updated, the person in charge of the navigation watch must ensure that any changes are communicated to other watchstanders.

(f) The assessment must be recorded in the Towing Vessel Record (TVR), official log, or, if the vessel has aTowing Safety Management System (TSMS), then in accordance with the TSMS applicable to the vessel. The entry must include: The date and time of the assessment, the name of the individual making the assessment, and the starting and ending points of the voyage or trip that the assessment covers.

§ 140.640 Pilothouse resource management.

This section applies to all towing vessels.

(a) The person in charge of the navigation watch must:

(1) Ensure that other members of the navigation watch:

(i) Share a common understanding of the navigational risks associated with the intended trip or voyage, and of agreed procedures of transit;

(ii) Understand the chain of command and the way decisions are made and responded to; and

(iii) Understand how and when to share information critical to the safety of the vessel throughout the trip or voyage.

(2) Ensure that the planned route is:

(i) Clearly displayed (in print or electronically) on charts or maps as appropriate in the pilothouse;

(ii) Continuously available to crewmembers with duties related to the safe navigation of the towing vessel, to verify any question or uncertainty on the course to be followed or to identify hazards to safe navigation; and

(iii) Updated as necessary at any change of watch, route, condition, and operational requirements during the voyage or trip.

(3) Ensure that watch change procedures provide a review of:

(i) Information critical to the safety of voyage (trip);

(ii) Procedures used to identify hazards to navigation; and

(iii) Information sharing procedures.

(4) Avoid handing over the watch if:

(i) There is reason to believe that the oncoming watchstander is not capable of carrying out the watchkeeping duties effectively; or

(ii) The night vision of the oncoming watchstander has not fully adjusted prior to assuming a night watch.

(b) Prior to assuming duties as person in charge of the navigation watch, a person must:

(1) Verify the planned route, taking into consideration all pertinent information to anticipate hazards to navigation safety;

(2) Verify the operational condition of the towing vessel; and

(3) Verify that there are adequate personnel available to assume the watch.

(c) If at any time the licensed mariner on watch is to be relieved when a maneuver or other action to avoid any hazard is taking place, the relief of that licensed mariner shall be deferred until such action has been completed.

§ 140.645 Navigation safety training.

(a) Prior to assuming duties related to the safe navigation of a towing vessel, each crewmember must receive training to ensure that they are familiar with:

(1) Watchstanding terms and definitions;

(2) Duties of a lookout;

(3) Communication with other watchstanders;

(4) Change of watch procedures;

(5) Procedures for reporting other vessels or objects; and

(6) Watchstanding safety.

(b) Crewmember training must be recorded in the towing vessel record or official logbook, or, if the vessel has a Towing Safety Management System (TSMS), then in accordance with the TSMS applicable to the vessel.

§ 140.650 Operational readiness of lifesaving and fire suppression and detection equipment.

The owner, managing operator, or master of a towing vessel must ensure that the vessel's lifesaving and fire suppression and detection equipment complies with the applicable requirements of parts 141 and 142 of this subchapter and are in good working order.

§ 140.655 Prevention of oil and garbage pollution.

(a) Each towing vessel must be operated in compliance with:

(1) Applicable sections of the Federal Water Pollution Control Act, including Section 311 of the Federal Water Pollution Control Act, as amended (33 U.S.C. 1321);

(2) Applicable sections of The Act to Prevent Pollution from Ships (33 U.S.C. 1901 *et seq.*); and

(3) Parts 151, 155, and 156 of 33 CFR, as applicable.

(b) Each towing vessel must be capable of preventing all oil and fuel spills from reaching the water during transfers by:

(1) Pre-closing of the scuppers/freeing ports, if the towing vessel is so equipped;

(2) Using fixed or portable containment of sufficient capacity to contain the most likely spill; or

(3) Pre-deploying sorbent material on the deck around vents and fills.

(c) No person may intentionally drain oil or hazardous material into the bilge of a towing vessel from any source.

§ 140.660 Vessel security.

Each towing vessel must be operated in compliance with:

(a) The Maritime Transportation Security Act of 2002 (46 U.S.C. chapter 701); and

(b) 33 CFR parts 101 and 104, as applicable. Subpart G—Navigation and Communication Equipment.

§ 140.700 Applicability.

This subpart applies to all towing vessels unless otherwise specified. Certain towing vessels will also remain subject to the navigation safety regulations in 33 CFR part 164.

§ 140.705 Charts and nautical publications.

(a) This section applies to a towing vessel not subject to the requirements of 33 CFR 164.72.

(b) A towing vessel must carry adequate and up-to-date information and equipment for the intended voyage, including:

(1) Charts, including electronic charts acceptable to the Coast Guard, of appropriate scale to make safe navigation possible. Towing vessels operating on the western rivers must have maps of appropriate scale issued by the Army Corps of Engineers (ACOE) or river authority;

(2) ''U.S. Coast Pilot'' or similar publication;

(3) Coast Guard light list; and

(4) Towing vessels that operate on the western rivers must have river stage(s) or Water Surface Elevations (WSE) as appropriate to the trip or route, as published by the U.S. Army Corps of Engineers, or a river authority must be available to the person in charge of the navigation watch.

(c) Extracts or copies from the publications listed in paragraph (b) of this section may be carried, so long as they are applicable to the route.

§ 140.710 Marine radar.

Requirements for marine radar are set forth in 33 CFR 164.72.

§ 140.715 Communications equipment.

(a) Towing vessels must meet the communications requirements of 33 CFR part 26 and 33 CFR 164.72, as applicable.

(b) Towing vessels not subject to the provisions of 33 CFR part 26 and 33 CFR 164.72 must have a Very High Frequency-Frequency Modulated (VHF–FM) radio installed and capable of monitoring VHF–FM Channels 13 and 16, except when transmitting or receiving traffic on other VHF–FM channels, when participating in a Vessel Traffic Service (VTS), or when monitoring a channel of a VTS. The VHF–FM radio must be installed at the operating station and connected to a functioning battery backup.

(c) All towing vessels must have at least one properly operating handheld VHF–FM radio in addition to the radios otherwise required.

§ 140.720 Navigation lights, shapes, and sound signals.

Each towing vessel must be equipped with navigation lights, shapes, and sound signals in accordance with the International Regulations for Prevention of Collisions at Sea (COLREGS) or 33 CFR part 84 as appropriate to its area of operation.

§ 140.725 Additional navigation equipment.

(a) This section applies to all towing vessels. Some vessels will also remain subject to the requirements of 33 CFR 164.72.

(b) Towing vessels must be equipped with the following equipment, as applicable to the area of operation:

(1) Fathometer (except Western Rivers);

(2) Search light, controllable from the vessel's main steering station and capable of illuminating objects at a distance of at least two times the length of the tow;

(3) Electronic position-fixing device, satisfactory for the area in which the vessel operates, if the towing vessel engages in towing seaward of the navigable waters of the U.S. or more than 3 nautical miles from shore on the Great Lakes;

(4) Magnetic compass or an illuminated swing-meter (Western rivers vessels only). The compass or swing-meter must be readable from the towing vessel's main steering station; and

(5) Certain towing vessels must also meet the Automatic Identification System requirements of 33 CFR 164.46.

Subpart H—Towing Safety

§ 140.800 Applicability.

This subpart applies to all towing vessels unless otherwise specified. Certain vessels will remain subject to the navigation safety regulations in 33 CFR parts 163 and 164.

§ 140.801 Towing gear.

The owner, managing operator, or master of a towing vessel must ensure that:

(a) The strength of each component used for securing the towing vessel to the tow and for making up the tow is adequate for its intended service.

(b) The size, material, and condition of towlines, lines, wires, push gear, cables, and other rigging used for making up a tow or securing the towing vessel to a tow must be appropriate for:

(1) The horsepower or bollard pull of the vessel;

(2) The static loads and dynamic loads expected during the intended service;

(3) The environmental conditions expected during the intended service; and

(4) The likelihood of mechanical damage.

(c) Emergency procedures related to the tow have been developed and appropriate training provided to the crew for carrying out their emergency duties.

§ 140.805 Towing safety.

Prior to getting underway, and giving due consideration to the prevailing and expected conditions of the trip or voyage, the person in charge of the navigation watch for a towing vessel must ensure that:

(a) The barges or vessels making up the tow are properly configured and secured;

(b) Equipment, cargo, and industrial components onboard the tow are properly secured and made ready for transit;

(c) The towing vessel is safely and securely made up to the tow; and

(d) The towing vessel has appropriate horsepower or bollard pull and is capable of safely maneuvering the tow.

§ 140.810 Towing of barges.

The requirements of 33 CFR part 163 also apply to certain towing vessels.

§ 140.815 Examination of towing gear.

(a) The owner, managing operator, or master of a towing vessel must ensure that a visual examination of all towing gear is conducted prior to placing it into service and at least once every 30 days while in service. The visual examination must include, but is not limited to:

(1) Towlines, bridles, face wires, spring lines, push gear, and other components used for towing or pushing;

(2) Wires, shackles, and other components used for making up a tow; and

(3) Winches, bits, cleats, and other towing vessel components.

(b) Any component found to be unsuitable must be removed from service or repaired prior to use.

§ 140.820 Recordkeeping for towing gear.

(a) The results of the visual examination, as outlined in § 140.815 of this subpart, must be documented in the Towing Vessel Record or official logbook, or, if the vessel has a Towing Safety Management System (TSMS), then in accordance with the TSMS applicable to the vessel.

(b) A record of the type, size, and service of each towline, bridle, face wire, and spring line must be available to the Coast Guard or third-party auditor for inspection.

Subpart I—Vessel Records

§ 140.900 Marine casualty reporting.

Each towing vessel must comply with the requirements of part 4 of this chapter for reporting marine casualties and retaining voyage records.

§ 140.905 Official logbooks.

(a) The following vessels are required by 46 U.S.C. 11301 to have an official logbook:

(1) A vessel of the United States, except one on a voyage from a port in the United States to a port in Canada, if the vessel is:

(i) On a voyage from a port in the United States to a foreign port; or

(ii) Of at least 100 gross tons and on a voyage between a port in the United States on the Atlantic Ocean and one on the Pacific Ocean.

(2) [Reserved]

(b) The Coast Guard furnishes, without fee, to masters of vessels of the United States the official logbook as Form CG–706B or CG–706C, depending on the number of persons employed as crew. The first several pages of this logbook list various acts of Congress governing logbooks and the entries required in them.

(c) When a voyage is completed, or after a specified time has elapsed, the master must file the official logbook containing required entries with the cognizant Officer in Charge, Marine Inspection at or nearest the port where the vessel may be.

§ 140.910 Towing vessel records.

(a) This section applies to a towing vessel other than a vessel operating only in a limited geographic area or a vessel required by § 140.905 of this subpart to maintain an official logbook.

(b) A towing vessel subject to this section must maintain a Towing Vessel Record (TVR) or, if the vessel has a Towing Safety Management System (TSMS), then other record as provided in accordance with the TSMS applicable to the towing vessel.

(c) The TVR must include a chronological record of events as required by this subchapter. They may be electronic or paper.

(d) Except as required by 46 CFR 140.900 and 144.905, records do not need to be filed with the Coast Guard, but must be kept available for review by the Coast Guard upon request. Records, unless required to be maintained for a longer period by statute or other Federal regulation, must be retained for at least 1 year after the date of the latest entry.

§ 140.915 Items to be recorded.

The following list of items must be recorded in the official log, Towing Vessel Record (TVR) or, if the vessel has a Towing Safety Management System (TSMS), then the TSMS applicable to the towing vessel:

(a) Personnel records, in accordance with § 140.400 of this part;

(b) Safety orientation, in accordance with § 140.410 of this part;

(c) Record of drills and training, in accordance with § 140.420 of this part;

(d) Operative navigational-safety equipment, in accordance with § 140.620 of this part;

(e) Navigation Assessment, in accordance with § 140.635 of this part;

(f) Navigation safety training, in accordance with § 140.645 of this part; and

(g) Towing gear, in accordance with § 140.820 of this part.

(h) Oil residue discharges and disposals, in accordance with § 140.655.

Subpart J—Penalties

§ 140.1000 Statutory penalties.

Violations of the provisions of this subchapter will subject the violator to the applicable penalty provisions of Subtitle II of Title 46, and Title 18, United States Code.

§ 140.1005 Suspension and revocation.

An individual is subject to proceedings under the provisions of 46 U.S.C. 7703 and part 5 of this chapter with respect to suspension or revocation of a license, certificate, document, or credential if the individual holds a license, certificate of registry, merchant mariner document, or merchant mariner credential and;

(a) Commits an act of misconduct, negligence or incompetence;

(b) Uses or is addicted to a dangerous drug; or

(c) Violates or fails to comply with this subchapter or any other law or regulation intended to promote marine safety.

PART 141—LIFESAVING

Subpart A—General

Subpart B—General Requirements for Towing Vessels

Subpart C—Lifesaving Requirements for Towing Vessels

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; Sec. 609 of Pub. L. 111–281; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 141.100 Purpose.

This part contains requirements for lifesaving equipment, arrangements, systems, and procedures on towing vessels.

§ 141.105 Applicability.

(a) This part applies to all towing vessels subject to this subchapter.

(b) A towing vessel on an international voyage, subject to the International Convention for the Safety of Life at Sea (SOLAS), 1974, as amended, must meet the applicable requirements in subchapter W of this chapter.

(c) Towing vessels in compliance with SOLAS will be deemed in compliance with this part.

§ 141.110 Organization of this part.

(a) Certain sections in this part contain functional requirements. Functional requirements describe the desired objective of the regulation. A towing vessel must meet the applicable functional requirements.

(b) Certain sections may also contain a prescriptive option to meet the functional requirements. A towing vessel that meets the prescriptive option will have complied with the functional requirements.

(c) If an owner or managing operator chooses to meet the functional requirement through means other than the prescriptive option, the means must be accepted by the cognizant Officer in Charge, Marine Inspection or, if the vessel has a Towing Safety Management System (TSMS), then by an approved third-party organization and documented in the TSMS applicable to the vessel.

§ 141.115 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 141.120 Incorporation by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register, in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in paragraph (b) of this section, the Coast Guard must publish notice of the change in the **Federal Register** and make the material available for inspection. All approved material is available at the U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street, SW., Washington, DC 20593–0001, or from the sources indicated in paragraph (b) of this section, or at the National Archives and Records Administration (NARA). For more information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal regulations/ibr_locations.html.*

(b) The material approved for incorporation by reference in this part and the sections affected are:

International Maritime Organization (IMO)	
Resolution A.760(18)—Symbols related to Life-Saving Appliances and Arrangements, 1993	141.340

Subpart B—General Requirements for Towing Vessels

§ 141.205 Towing Safety Management System (TSMS).

If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS must:

(a) Include policies and procedures to ensure compliance with this part; and

(b) Provide objective evidence that documents compliance with the TSMS.

§ 141.215 [Reserved]

§ 141.220 General provisions.

(a) Unless otherwise specified, all lifesaving equipment must be of an approved type.

(b) Where equipment in this subpart is required to be of an approved type, such equipment requires the specific approval of the Coast Guard. A listing of approved equipment and materials may be found at *http://cgmix.uscg.mil/equipment.* Each cognizant Officer in Charge, Marine Inspection (OCMI) may be contacted for information concerning approved equipment and materials.

§ 141.225 Alternative requirements.

(a) A towing vessel may meet the requirements of this part by being equipped with appropriate alternate arrangements or equipment as permitted by this subpart and, for vessels with a TSMS, documented in the TSMS applicable to the vessel.

(b) The cognizant Officer in Charge, Marine Inspection (OCMI) may require a towing vessel to carry specialized or additional lifesaving equipment if:

(1) The cognizant OCMI determines that the conditions of the voyage render the requirements of this part inadequate; or

(2) The vessel is operated in globally remote areas or severe environments not covered under this part. Such areas may include, but are not limited to, Polar Regions, remote islands, areas of extreme weather, and other remote areas where timely emergency assistance cannot be anticipated.

§ 141.230 Readiness.

The master must ensure that all lifesaving equipment is properly maintained and ready for use at all times.

§ 141.235 Examination, testing, and maintenance.

(a) All lifesaving equipment must be tested and maintained in accordance with the minimum requirements of § 199.190 of this chapter and, if the vessel has a Towing Safety Management System (TSMS), with the TSMS applicable to the towing vessel.

(b) The records of tests and examinations must be maintained in accordance with the TSMS applicable to the towing vessel, if the vessel has a TSMS, or with the towing vessel record or the vessel's official logbook. The following minimum information is required:

(1) The dates when tests and examinations were performed, the number and/or other identification of each unit tested and examined, and the name(s) of the person(s) and/or third-party auditor conducting the tests and examinations.

(2) Receipts and other records documenting these tests and examinations must be retained and made available upon request.

§ 141.240 Requirements for training crews.

Training requirements are contained in part 140 of this subchapter.

Subpart C—Lifesaving Requirements for Towing Vessels

§ 141.305 Survival craft requirements for towing vessels.

(a) *General purpose.* Survival craft provide a means for survival when evacuation from the towing vessel is necessary. The craft and related equipment should be selected so as to provide for the basic needs of the crew, such as shelter from life threatening elements, until rescue resources are expected to arrive, taking into account the scope and nature of the towing vessel's operations.

(b) *Functional requirements.* A towing vessel's survival craft must meet the functional requirements of paragraphs (b)(1) through (5) of this section. The design, testing, and examination scheme for meeting these functional requirements must be submitted as part of any Towing Safety Management System (TSMS) issued under part 138 of this chapter. Survival craft must:

(1) Be readily accessible;

(2) Have an aggregate capacity to accommodate the total number of individuals onboard, as specified in paragraph (c) of this section;

(3) Provide a means for sheltering its complement appropriate to the route;

(4) Provide minimum equipment for survival if recovery time is expected to be greater than 24 hours; and

(5) Be marked so that an individual not familiar with the operation of the specific survival craft has sufficient guidance to utilize the craft for its intended use.

(6) By 2015, no survival craft may be approved unless the craft ensures that no part of an individual is immersed in water.

(c) *Prescriptive requirements.* Compliance with the functional requirements of paragraph (b) of this section may be met by meeting the prescriptive requirements of this paragraph.

(1) Except as provided in paragraphs (c)(2) through (5) of this section, each towing vessel must carry the survival craft specified in Table 141.305 of this section, as appropriate for the towing vessel, in an aggregate capacity to accommodate the total number of individuals onboard. Equipment requirements are based on the area in which a towing vessel is operating, not the route for which it is certificated; however, the towing vessel must be equipped per the requirements of its certificated route at the time of certification.

TABLE 141.305—SURVIVAL CRAFT

	Area of operation						
	Limited geographic area	Rivers	Great Lakes and LBS		Coastwise and Ltd. coastwise		Oceans
			< 3 miles from shore	> 3 miles from shore	< 3 miles from shore	> 3 miles from shore	
COLD WATER OPERATION							
Buoyant Apparatus	[1]	...	...	...	...	...	...
Life Float	[1]	...	...	...	...	...	...
Inflatable Buoyant Apparatus	[1]	[2] [4] [5] [6] 100%	[2] 100%	...	[2] 100%	...	...
Inflatable Liferaft with SOLAS A Pack	[1]	...	...	...	...	...	100%
Inflatable Liferaft with SOLAS B Pack	[1]	...	...	100%	...	100%	...
WARM WATER OPERATION							
Buoyant Apparatus	[1]	[2] [4] [5] [6] 100%	[2] 100%	[2] 100%	[2] 100%	...	...
Life Float	[1]	...	...	...	...	...	...
Inflatable Buoyant Apparatus	[1]	...	...	...	...	...	...
Inflatable Liferaft with SOLAS A Pack	[1]	...	...	...	...	...	100%
Inflatable Liferaft with SOLAS B Pack	[1]	...	...	...	...	[3] 100%	...

[1] Unless survival craft requirements are determined to be necessary by the cognizant OCMI or a TSMS applicable to the towing vessel.

[2] A skiff may be substituted for all or part of required equipment if capable of being launched within five minutes under all circumstances (*see* § 141.330).

[3] IBA may be accepted or substituted if the vessel carries a 406 MHz Cat 1 EPIRB meeting 47 CFR Part 80.

[4] A towing vessel may be exempt from this requirement if it carries a 406 MHz Cat 1 EPIRB meeting 46 CFR 47 Part 80.

[5] A towing vessel designed for pushing ahead when operating on rivers and canals need not carry survival craft if a TSMS applicable to the towing vessel contains procedures for evacuating crewmembers onto the tow or other safe location.

[6] Not required for towing vessels operating within 1 mile of shore unless determined to be necessary by the cognizant OCMI or a TSMS applicable to the towing vessel.

(2) A towing vessel may continue to use a survival craft, other than an inflatable liferaft, installed onboard the vessel before [EFFECTIVE DATE OF FINAL RULE] provided it is of the same type as required in Table 141.305 of this section, as appropriate for the vessel type and maintained in good and serviceable condition.

(3) A towing vessel may continue to use an inflatable liferaft installed onboard the vessel before [EFFECTIVE DATE OF FINAL RULE], provided it is equipped with the equipment pack required in Table § 141.305 of this section, as appropriate for the vessel type and maintained in good and serviceable condition.

(4) An approved lifeboat may be substituted for any survival craft required by this section, provided it is arranged and equipped in accordance with part 199 of this chapter.

(5) Each towing vessel operating within a limited geographic area need not carry a survival craft unless it is determined to be necessary by the cognizant Officer in Charge, Marine Inspection, or a TSMS applicable to the towing vessel.

(6) By 2015, no survival craft may be approved unless the craft ensures that no part of an individual is immersed in water.

§ 141.310 Stowage of survival craft.

Survival craft may be stowed in accordance with the Towing Safety Management System applicable to the towing vessel, but must, at a minimum, meet the requirements of § 199.130 of this chapter, as far as is practicable on existing towing vessels.

§ 141.315 Marking of survival craft and stowage locations.

Survival craft may be marked in accordance with the Towing Safety Management System applicable to the vessel, but must, at a minimum, meet the requirements of §§ 199.176 and 199.178 of this chapter.

§ 141.320 Inflatable survival craft placards.

Every towing vessel equipped with an inflatable survival craft must have approved placards or otherwise post instructions for launching and inflating inflatable survival craft in conspicuous places near each inflatable survival craft for the information of persons onboard.

§ 141.325 Survival craft equipment.

(a) Each item of survival craft equipment must be of good quality, effective for the purpose it is intended to serve, and secured to the craft.

(b) Each towing vessel carrying a lifeboat must carry equipment in accordance with 46 CFR 199.175.

(c) Each life float and buoyant apparatus must be fitted with a lifeline, pendants, a painter, and floating electric water light approved under subpart 161.010 of this chapter.

§ 141.330 Other survival craft.

A skiff may be substituted for all or part of the approved survival craft as permitted by Table 141.305 (in § 141.305) of this part. The skiff must meet the following requirements:

(a) Must be capable of being launched within 5 minutes under all circumstances.

(b) Must be of suitable size for all persons onboard;

(c) Must not exceed the loading specified on the capacity plate;

(d) Must not contain modifications affecting the buoyancy or structure of the skiff;

(e) Must be of suitable design for the vessel's intended service; approval by the Coast Guard is not required; and

(f) Must be marked in accordance with 46 CFR part 178 and 46 CFR 199.176.

(g) By 2015, no survival craft may be approved unless the craft ensures that no part of an individual is immersed in water.

§ 141.335 Personal lifesaving requirements for towing vessels.

Personal lifesaving requirements are summarized in Table 141.335 of this section. Equipment requirements are based on the area in which a vessel is operating, not the route for which it is certificated.

TABLE 141.335—PERSONAL LIFESAVING EQUIPMENT

	Area of Operation						
	Limited geographic area	Rivers	Great Lakes and LBS		Coastwise and Ltd. coastwise		Oceans
			< 3 miles from shore	> 3 miles from shore	< 3 miles from shore	> 3 miles from shore	
Lifejackets	1 per person	1 per person onboard. In addition, for vessels with berthing aboard, 1 per watch stander located at each watch station.					
Immersion Suits	....	....	1 per person onboard. In addition, *see* 141.350(a)(2).				
Work Vests	Required to be worn when dispatched from the towing vessel or working without rails and guard on the exterior of the vessel.						

§ 141.340 Lifejackets.

Each towing vessel must meet the requirements of 46 CFR 199.70(b) and (d), except that:

(a) A lifejacket meeting the requirements of 46 CFR 199.620(c) is acceptable.

(b) Child lifejackets are not required.

(c) For towing vessels with berthing aboard, a sufficient number of additional lifejackets must be carried so that a lifejacket is immediately available for persons at each normally manned watch station.

(d) If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS may provide for an appropriate, alternative number of lifejackets for the vessel, but there must be at least one lifejacket for each person onboard. Any TSMS applicable to the towing vessel must specify the number and location of lifejackets in such a manner as to facilitate immediate accessibility at normally occupied spaces including, but not limited to, accommodation spaces and watch stations.

(e) The requirements of 46 CFR 199.70(b)(2)(iii) do not apply to stowage positions for lifejackets, other than lifejackets stowed in a berthing space or stateroom.

(f) Each lifejacket container must also be marked in block capital letters and numbers with the minimum quantity, identity, and, if sizes other than adult or universal sizes are used on the vessel, the size of the lifejackets stowed inside the container. The equipment may be identified in words or with the appropriate symbol from IMO Resolution A.760(18) incorporated by reference in § 141.120 of this part); and

(g) Where, due to the particular arrangements of the vessel, the lifejackets under paragraph (a) of this section could become inaccessible, any TSMS applicable to the vessel may include suitable alternative arrangements.

(h) A lifejacket light described in 46 CFR 199.620(e) may be used on vessels that are not in international service.

§ 141.345 Lifejacket placards.

(a) Placards containing instructions for the donning and use of the lifejackets aboard the vessel must be posted in conspicuous places for all persons onboard.

(b) If there is no suitable mounting surface, the lifejacket placards must be available to all persons onboard for familiarization.

§ 141.350 Immersion suits.

(a) *General.* Except for a towing vessel operating on rivers or in a limited geographic area, each towing vessel operating north of 32 degrees North latitude or south of 32 degrees South latitude must carry the number of immersion suits as prescribed in this subsection:

(1) At least one immersion suit, approved under subpart 160.171 of this chapter, must be the appropriate size for each person onboard, as noted in Table 141.335 (in § 141.335) of this part; and

(2) In addition to the immersion suits required under paragraph (a)(1) of this section, each watch station, work station, and industrial work site must have enough immersion suits to equal the number of persons normally on watch in, or assigned to, the station or site at one time. However, an immersion suit is not required at a station or site for a person whose cabin or berthing area (and the immersion suits stowed in that location) is readily accessible to the station or site.

(3) If a TSMS is applicable to the towing vessel, the TSMS may provide for an appropriate, alternative number of immersion suits for the vessel, but there must be at least one immersion suit of the appropriate size for each person onboard if the towing vessel is required to carry them as prescribed in paragraph (a)(1) of this section. Any TSMS applicable to the towing vessel must specify the number and location of the immersion suits in such a manner as to facilitate immediate accessibility at normally occupied spaces, including

but not limited to, accommodation spaces and watch stations.

(b) *Attachments and Fittings.* Immersion suits must carried on towing vessels must meet the requirements of 46 CFR 199.70(c) and (d).

§ 141.360 Lifebuoys.

(a) A towing vessel must have one or more lifebuoys as follows:

(1) A towing vessel less than 26 feet length must carry a minimum of one lifebuoy of not less than 510 millimeters (20 inches) in diameter;

(2) A towing vessel of at least 26 feet, but less than 79 feet, in length must carry a minimum of three lifebuoys located in positions to be spread around the vessel where personnel are normally present. Lifebuoys must be at least 610 millimeters (24 inches) in diameter;

(3) A towing vessel 79 feet or more in length must carry four lifebuoys, plus one lifebuoy on each side of the primary operating station and one lifebuoy at each alternative operating station if the vessel is so equipped. Lifebuoys must be at least 610 millimeters (24 inches) in diameter; or

(4) If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS may provide for an appropriate, alternative number of lifebuoys for the vessel. Any TSMS applicable to the towing vessel must specify the number and location of lifebuoys in such a manner as to facilitate rapid deployment of ring buoys from exposed decks, including the pilot house.

(b) Each lifebuoy on a towing vessel must meet the requirements of 46 CFR 199.70(a), except that:

(1) Lifebuoys must be orange in color, if on a vessel on an oceans or coastwise route.

(2) At least two lifebuoys on a towing vessel greater than 26 feet must be fitted with a floating electric water light approved under subpart 161.010 of this chapter. If the towing vessel is limited to daytime operation, no floating electric water light is required. The floating electric water light may not be attached to the lifebuoys fitted with lifelines.

(3) Each lifebuoy with a floating electric water light must have a lanyard of at least 910 millimeters (3 feet) in length, but not more than 1,830 millimeters (6 feet), securing the water light around the body of the ring buoy.

(4) Each floating electric water light on a vessel carrying only one lifebuoy must be attached by the lanyard with a corrosion-resistant clip to allow the water light to be quickly disconnected from the ring buoy. The clip must have a strength of at least 22.7 kilograms (50 pounds).

§ 141.365 Means for recovery of persons in the water.

If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS must include procedures for the prompt recovery of a person from the water and for the training of crewmembers responsible for recovery in effectively implementing such procedures.

§ 141.370 Miscellaneous lifesaving requirements for towing vessels.

Miscellaneous lifesaving requirements are summarized in Table 141.370 of this section. Equipment requirements are based on the area in which a towing vessel is operating, not the route for which it is certificated.

TABLE 141.370—MISCELLANEOUS LIFESAVING EQUIPMENT

	Area of operation						
	Limited geographic area	Rivers	Great Lakes and LBS: < 3 miles from shore	Great Lakes and LBS: > 3 miles from shore	Coastwise and Ltd. Coastwise: < 3 miles from shore	Coastwise and Ltd. Coastwise: > 3 miles from shore	Oceans
Visual Distress Signals (§ 141.375).	3 and 3	3 and 3	3 and 3	6 and 6; or 12 parachute flares.	3 and 3	6 and 6; or 12 parachute flares.	6 and 6; or 12 parachute flares.
EPIRBS (§ 141.380)	....	....	....	Yes	....	Yes	Yes, Type Accepted Category 1.
Line Throwing Appliances (§ 141.385).	....	....	....	....	....	....	Yes, 1.

§ 141.375 Visual distress signals.

(a) *Operating on oceans and other bodies of water.* A towing vessel operating on oceans, coastwise, limited coastwise, Great Lakes, or lakes, bays and sounds must carry:

(1) Six hand red flare distress signals, as approved under 46 CFR subpart 160.021 or other standard specified by the Coast Guard; and

(2) Six hand orange smoke distress signals, as approved under 46 CFR 160.037 or other standard specified by the Coast Guard.

(b) *Operating on rivers and other bodies of water.* A towing vessel operating on rivers or western rivers, and not more than 3 nautical miles from shore upon limited coastwise, great lakes or lakes, or bays and sounds, must carry:

(1) Three hand red flare distress signals, as approved under 46 CFR subpart 160.021 or other standard specified by the Coast Guard.

(2) Three hand orange smoke distress signals, as approved under 46 CFR subpart 160.037 or other standard specified by the Coast Guard.

(c) *Operating in limited geographic areas.* A towing vessel operating in a limited geographic area must carry:

(1) Three hand red flare distress signals approved under 46 CFR subpart 160.021 or other standard specified by the Coast Guard.

(2) Three hand orange smoke distress signals, as approved under 46 CFR subpart 160.037 or other standard specified by the Coast Guard.

(d) *Substitutions.* (1) A rocket parachute flare, as approved under 46 CFR subpart 160.036 or other standard specified by the Coast Guard, may be substituted for any of the hand red flare distress signals, as required under paragraph (a) or (b) of this section; or

(2) One of the following may be substituted for any of the hand orange smoke distress signals, as required under paragraph (a) or (b) of this section:

(i) A rocket parachute flare, as approved under 46 CFR subpart 160.036 or other standard specified by the Coast Guard;

(ii) A hand red flare distress signal, as approved under 46 CFR subpart 160.021

or other standard specified by the Coast Guard; or

(iii) A floating orange smoke distress signal, as approved under 46 CFR subpart 160.022 or other standard specified by the Coast Guard.

(e) *Exemption.* A vessel operating in a limited geographic area on a short run limited to approximately 30 minutes away from the dock is not required to carry distress flares and smoke signals under this section.

(f) *Stowage.* Each pyrotechnic distress signal carried to meet this section must be stowed in one of the following:

(1) A portable watertight container carried at the operating station. Portable watertight containers for pyrotechnic distress signals must be of a bright color and must be clearly marked in legible contrasting letters at least 12.7 millimeters (0.5 inches) high with ''DISTRESS SIGNALS''; or

(2) A pyrotechnic locker secured above the freeboard deck, away from heat, in the vicinity of the operating station.

§ 141.380 Emergency position indicating radiobeacon (EPIRB).

(a) Each towing vessel operating on oceans, coastwise, limited coastwise, or beyond 3 nautical miles from shore upon the Great Lakes must carry a Category 1, 406 MHz satellite Emergency Position Indicating Radio Beacon (EPIRB) which meets the requirements of 47 CFR part 80.

(b) When the towing vessel is underway, the EPIRB must be stowed in its float-free bracket with the controls set for automatic activation and be mounted in a manner so that it will float free if the towing vessel sinks.

(c) The name of the towing vessel must be marked or painted in clearly legible letters on each EPIRB, except on an EPIRB in an inflatable liferaft.

(d) The owner or managing operator must maintain valid proof of registration.

§ 141.385 Line throwing appliance.

Each towing vessel operating in oceans service must have a line throwing appliance approved under subpart 160.040 of this chapter.

(a) *Stowage.* The line throwing appliance and its equipment must be readily accessible for use.

(b) *Additional equipment.* The following equipment for the line throwing appliance is required:

(1) The equipment on the list provided by the manufacturer with the approved appliance; and

(2) An auxiliary line that—

(i) Is at least 450 meters (1,500 feet) long; and

(ii) Has a breaking strength of at least 40 kilonewtons (9,000 pounds-force); and

(iii) Is, if synthetic, of a dark color or certified by the manufacturer to be resistant to deterioration from ultraviolet light.

PART 142—FIRE PROTECTION

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 142.100 Purpose.

This part describes the requirements for fire suppression and detection equipment and arrangements on towing vessels.

§ 142.105 Applicability.

This part applies to all towing vessels subject to this subchapter.

§ 142.110 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 142.115 Incorporation by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the Coast Guard must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.* Also, it is available for inspection at U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street, SW., Washington, DC 20593–0001, and is available from the sources listed in paragraph (b) of this section.

(b) The materials approved for incorporation by reference in this part and the sections affected are:

National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02269–9101	
NFPA 10 (Chapter 7)—Portable Fire Extinguishers, 2007	142.240
NFPA 1971—Standard on Protective Ensembles for Structural Fire-Fighting and Proximity Fire-Fighting, 2007	142.345
Underwriters Laboratories Standard, 12 Laboratory Drive, Research Triangle Park, NC 27709–3995	
UL 217—Single and Multiple Station Smoke Detectors	142.335
UL 1275—Flammable Storage Cabinet	142.225

Subpart B—General Requirements for Towing Vessels

§ 142.200 Towing Safety Management System (TSMS).

If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS must:

(a) Include policies and procedures to ensure compliance with this part; and

(b) Provide objective evidence that documents compliance with the TSMS.

§ 142.205 Vessels built to alternate standards.

(a) Towing vessels that comply with The International Convention for the Safety of Life at Sea (SOLAS), 1974, as amended will be deemed to be in compliance with this part.

(b) Alternate standards may be used where it can be shown that they provide an equivalent level of safety and performance.

§ 142.210 Alternate arrangements or equipment.

(a) A towing vessel may comply with the requirements of this subpart by being equipped with appropriate alternate arrangements or equipment as permitted by this subpart and documented in the Towing Safety Management System applicable to the towing vessel.

(b) The cognizant Officer in Charge, Marine Inspection (OCMI) may require a towing vessel to carry specialized or additional fire protection, suppression, or detection equipment if:

(1) The cognizant OCMI determines that the conditions of the voyage render the requirements of this part inadequate; or

(2) The towing vessel is operated in globally remote areas or severe environments not covered under this part. These areas may include, but are not limited to, Polar Regions, remote islands, areas of extreme weather, and other remote areas where timely emergency assistance cannot be anticipated.

§ 142.215 Approved equipment.

(a) All hand-portable fire extinguishers, semi-portable fire-extinguishing systems, and fixed fire-extinguishing systems must be of an approved type.

(b) Where equipment in this subpart is required to be of an approved type, such equipment requires the specific approval of the Coast Guard. A listing of approved equipment and materials may be found online at *http://cgmix.uscg.mil/equip*. Each cognizant Officer in Charge, Marine Inspection (OCMI) may be contacted for information concerning approved equipment and materials.

§ 142.220 Fire hazards to be minimized.

Each towing vessel must be maintained and operated so as to minimize fire hazards and to ensure the following:

(a) All bilges and void spaces are kept free from accumulation of combustible and flammable materials and liquids;

(b) Storage areas are kept free from accumulation of combustible materials insofar as practicable; and

(c) Internal combustion engine exhaust ducts and galley exhaust ducts are insulated with noncombustible insulation if less than 450 mm (18 inches) away from combustibles.

§ 142.225 Storage of flammable or combustible products.

(a) A towing vessel that has paints, coatings, or other flammable or combustible products onboard must have a designated storage area.

(b) The storage area may be any room or compartment that is free of ignition sources. A flammable storage cabinet that satisfies Underwriters Laboratories Standard (UL) 1275 (incorporated by reference in § 142.105 of this part) may be used, or other suitable steel container that provides an equivalent level of protection. If a flammable storage cabinet or steel container is used, it must be secured to the vessel so that it does not move.

(c) A B–II portable fire extinguisher must be located near the storage area. This is in addition to the portable fire extinguishers required by Table 142.305 (in § 142.305) of this part.

§ 142.230 Hand-portable fire extinguishers and semi-portable fire-extinguishing systems.

(a) Hand-portable fire extinguishers and semi-portable fire-extinguishing systems are classified by a combination letter and Roman numeral. The letter indicates the type of fire which the unit could be expected to extinguish, and the Roman numeral indicates the relative size of the unit.

(b) For the purpose of this subchapter, all required hand-portable fire extinguishers and semi-portable fire-extinguishing systems must include Type B classification, suitable for extinguishing fires involving flammable liquids, grease, *etc.*

(c) The number designations for size run from ''I'' for the smallest to ''V'' for the largest. Sizes I and II are hand-portable fire extinguishers; sizes III, IV, and V are semi-portable fire-extinguishing systems, which must be fitted with hose and nozzle or other practical means to cover all portions of the space involved. Examples of the sizes for some of the typical hand-portable fire extinguishers and semi-portable fire-extinguishing systems appear in Table 142.230(c) of this section.

TABLE 142.230(c)—PORTABLE AND SEMI-PORTABLE EXTINGUISHERS

Classification	Foam, liters (gallons)	Carbon dioxide, kilograms (pounds)	Dry chemical, kilograms (pounds)
B–I	4.75 (1.25)	2 (4)	1 (2)
B–II	9.5 (2.5)	7 (15)	4.5 (10)
B–III	45 (12)	16 (35)	9 (20)
B–IV	75 (20)	23 (50)	13.5 (30)
B–V	125 (33)	45 (100)	23 (50)

(d) All hand-portable fire extinguishers and semi-portable fire-extinguishing systems must have a permanently attached name plate giving the name of the item, the rated capacity in gallons, quarts, or pounds, the name and address of the approving person or firm, and the manufacturer's identifying mark.

§ 142.235 Fixed fire-extinguishing systems.

(a) When a fixed fire-extinguishing system is installed on a towing vessel, it must be a type approved by the Coast Guard.

(b) If the system is a carbon-dioxide type, then it must be designed and installed in accordance with subpart 76.15 of this chapter.

§ 142.240 Examination, testing, and maintenance.

(a) All fire suppression and detection equipment and systems on board a towing vessel must be tested and maintained in accordance with the attached nameplate, manufacturer's approved design manual or as otherwise provided in any Towing Safety Management System (TSMS) applicable to the vessel.

(b) The records of examinations and tests must be recorded in accordance with any TSMS applicable to the vessel, the towing vessel record, or the vessel's official logbook. The following minimum information is required:

(1) For tests: the dates when tests and examinations were performed, the number and/or other identification of each unit tested and examined, and the name(s) of the person(s) and/or third-party auditor conducting the tests and examinations; and

(2) Receipts and other records generated by these tests and examinations must be retained for at least 1 year after the expiration of the COI and made available upon request.

(c) All hand-portable fire extinguishers, semi-portable fire-extinguishing systems, fire detection systems, and fixed fire-extinguishing systems, including ventilation, machinery shutdowns, and dampers onboard the vessel, must be tested or examined at least once every 12 months, as prescribed in paragraph (d) of this section.

(d) *Tests and examinations.* (1) Portable fire extinguishers must be tested in accordance with the examinations, maintenance procedures, and hydrostatic pressure tests required by Chapter 7 of NFPA 10, Portable Fire Extinguishers (incorporated by reference in § 142.105 of this subchapter), with the frequency as specified by NFPA 10. In addition, carbon dioxide and Halocarbon portable fire extinguishers must be refilled when the net content weight loss exceeds that specified for fixed systems in Table 142.240 of this section.

(2) Semi-portable and fixed gas fire-extinguishing systems must be inspected and tested, as required by Table 142.240 of this section, in addition to the tests required by §§ 147.60 and 147.65 of subchapter N of this chapter.

(3) Flexible connections and discharge hoses on all semi-portable extinguishers and fixed gas extinguishing systems must be inspected and tested in accordance with § 147.65 of this chapter;

(4) All cylinders containing compressed gas must be tested and marked in accordance with § 147.60 of this chapter;

(5) All piping, controls, valves, and alarms must be examined; and the operation of controls, alarms, and ventilation shutdowns for each fixed fire-extinguishing system and detecting system must be verified, to determine that the system is operating properly;

(6) The fire main system must be charged, and appropriate pressure must be verified at the most remote and highest outlets;

(7) All fire hoses must be examined and subjected to a test pressure equivalent to the maximum service pressure;

(8) All smoke and fire detection systems, including sensors and alarms must be tested; and

(9) All fire hoses which are defective and incapable of repair must be destroyed.

TABLE 142.240—SEMI-PORTABLE AND FIXED FIRE EXTINGUISHING SYSTEMS

Type system	Test
Carbon dioxide	Weigh cylinders. Recharge if weight loss exceeds 10 percent of weight of charge. Test time delays, alarms, and ventilation shutdowns with carbon dioxide, nitrogen, or other nonflammable gas as stated in the system manufacturer's instruction manual. Examine hoses and nozzles to be sure they are clean.
Halon	Weigh cylinders. Recharge if weight loss exceeds 5 percent of weight of charge. If the system has a pressure gauge, recharge if pressure loss (adjusted for temperature) exceeds 10 percent. Test time delays, alarms, and ventilation shutdowns with carbon dioxide, nitrogen, or other nonflammable gasses stated in the system manufacturer's instruction manual. Examine hoses and nozzles to be sure they are clean.
Dry Chemical (cartridge operated)	Examine pressure cartridge and replace if end is punctured or if determined to have leaked or is in an unsuitable condition. Examine hose and nozzle to see if they are clear. Insert charged cartridge. Ensure dry chemical is free flowing (not caked) and extinguisher contains full charge.
Dry chemical (stored pressure)	See that pressure gauge is within operating range. If not, or if the seal is broken, weigh or otherwise determine that extinguisher is fully charged with dry chemical. Recharge if pressure is low or dry chemical is needed.
Foam (stored pressure)	See that pressure gauge, if so equipped, is within the operating range. If not, or if the seal is broken, weigh or otherwise determine that extinguisher is fully charged with foam. Recharge if pressure is low or foam is needed. Replace premixed agent every 3 years.
Halocarbon	Recharge or replace if weight loss exceeds 5 percent of weight of charge, or if pressure loss exceeds 10 percent of specified gauge pressure, adjusted for temperature.
Inert gas	Recharge or replace if cylinder pressure loss exceeds 5 percent of specified gauge pressure, adjusted for temperature.
Water mist	Maintain system in accordance with the maintenance instructions in the system manufacturer's design, installation, operation, and maintenance manual.

§ 142.245 Requirements for training crews to respond to fires.

(a) *Drills and instruction.* The master of a towing vessel must ensure that each crewmember participates in fire fighting drills and receives instruction at least once each month. The instruction may coincide with the drills, but is not required. All crewmembers must be familiar with their fire fighting duties, and, specifically how to:

(1) Fight a fire in the engine room and elsewhere onboard the towing vessel, including how to—

(i) Operate all of the fire-extinguishing equipment onboard the towing vessel;

(ii) Stop any mechanical ventilation system for the engine room and effectively seal all natural openings to the space to prevent leakage of the extinguishing agent; and

(iii) Operate the fuel shut-off(s) for the engine room.

(2) Activate the general alarm.

(3) Report inoperative alarm systems and fire detection systems; and

(4) Don a fireman's outfit and a self-contained breathing apparatus, if the vessel is so equipped.

(b) *Alternative form of instruction.* Video training, followed by a discussion led by someone familiar with the contingencies listed in paragraph (a) of this section, is an acceptable, alternative form of instruction. This instruction may occur either onboard or off the towing vessel.

(c) *Participation in drills.* Drills must take place onboard the towing vessel as if there were an actual emergency. They must include:

(1) Participation by all crewmembers;

(2) Breaking out and using, or simulating the use of, emergency equipment;

(3) Testing of all alarm and detection systems; and

(4) Putting on protective clothing by at least one person, if the towing vessel is so equipped.

(d) *Safety orientation.* The master must ensure that each crewmember who has not participated in the drills required by paragraph (a) of this section and received the instruction required by that paragraph receives a safety orientation within 24 hours of reporting for duty. The safety orientation must cover the particular contingencies listed in paragraph (a) of this section.

(e) *Recording.* Training must be recorded in accordance with the provisions of part 140 of this subchapter.

Subpart C—Equipment Requirements

§ 142.300 General.

Excepted vessels, as defined in § 136.110 of this subchapter, need not comply with the provisions of §§ 142.315 through 142.340 of this subpart.

§ 142.305 Fire-extinguishing equipment required.

(a) Towing vessels of 65 feet or less in length must carry at least the minimum number of hand-portable fire extinguishers set forth in Table 142.305(a) of this section.

TABLE 142.305(a)—HAND-PORTABLE FIRE EXTINGUISHERS

Length, feet	Minimum number of B–I hand portable fire extinguishers required [1]	
	No fixed fire-extinguishing system in machinery space	Fixed fire-extinguishing system in machinery space
Under 16	1	0
16 and over, but under 26 [2]	1	0
26 and over, but under 40	2	1
40 and over, but not over 65	3	2

[1] One B–II hand-portable fire extinguisher may be substituted for two B–I hand portable fire extinguishers.
[2] *See* § 136.105 Applicability concerning vessels under 26 feet.

(b)(1) Towing vessels of more than 65 feet in length must carry at least the minimum number of hand portable fire extinguishers set forth in Table 142.305(b)(1) of this section.

TABLE 142.305(b)(1)

Gross tonnage—		Minimum number of B–II hand portable fire extinguishers
Over	Not over	
	50	1
50	100	2
100	500	3
500	1,000	6
1,000		8

(2) In addition to the hand portable extinguishers required by paragraph (b)(1) of this section, one Type B–II hand-portable fire extinguisher must be fitted in the engine room for each 1,000 brake horsepower of the main engines or fraction thereof. A towing vessel is not required to carry more than six such extinguishers.

§ 142.310 Vessels contracted for prior to November 19, 1952.

(a) Towing vessels contracted for construction prior to November 19, 1952, must meet the applicable provisions of this part concerning the number and general type of equipment required.

(b) Existing lists of equipment and installations previously approved, but not meeting the applicable requirements for type approval, may be continued in service so long as they are in good condition.

(c) All new installations and replacements must meet the requirements of this part.

§ 142.315 Additional fire-extinguishing equipment requirements.

(a) A towing vessel that is:

(1) Certificated for rivers, lakes, bays, and sounds; or

(2) Certificated for limited coastwise, coastwise, oceans or waters beyond 3 nautical miles from shore on the Great Lakes, whose contract for construction was executed prior to August 27, 2003, must have:

(i) The minimum number of hand-portable fire extinguishers required by § 142.305 of this part; and

(ii) An approved B–V semi-portable fire-extinguishing system to protect the engine room; or

(iii) A fixed fire-extinguishing system installed to protect the engine room.

(b) A towing vessel whose contract for construction was executed on or after August 27, 2003, and is certificated for limited coastwise, coastwise, oceans, or beyond 3 nautical miles from shore on the Great Lakes, must be equipped with:

(1) The minimum number of hand-portable fire extinguishers required by § 142.305 of this part; and

(2) An approved B–V semi-portable fire-extinguishing system to protect the engine room; and

(3) A fixed fire-extinguishing system installed to protect the engine room.

(4) Paragraph (b) of this section does not apply to any towing vessel pushing a barge ahead or hauling a barge alongside when the barge's coastwise, limited coastwise, or Great Lakes route is restricted, as indicated on its Certificate of Inspection, so that the barge may operate ''in fair weather only, within 12 miles of shore'' or with words to that effect.

§ 142.325 Fire pumps, fire mains, and fire hoses.

Each towing vessel must have either a self-priming, power-driven, fixed fire pump, a fire main, and hoses and nozzles in accordance with paragraphs (a) through (d) of this section; or a portable pump, and hoses and nozzles, in accordance with paragraphs (e) and (f) of this section.

(a) A fixed fire pump must be capable of:

(1) Delivering water simultaneously from the two highest hydrants, or from both branches of the fitting if the highest hydrant has a Siamese fitting, at a pitot-tube pressure of at least 344 kilopascals (kPa), 50 pounds per square inch (psi), and a flow rate of at least 300 liters per minute (LPM), 80 gallons per minute (gpm), and

(2) Being energized remotely from a safe place outside the engine room and from the pump.

(b) All suction valves necessary for the operation of the fire main must be kept in the open position or capable of operation from the same place where the remote fire pump control is located.

(c) The fire main must have a sufficient number of fire hydrants with attached hose to reach any part of the machinery space using a single length of fire hose.

(d) The hose must be lined commercial fire hose, at least 40 millimeters (1.5 inches) in diameter, 15 meters (50 feet) in length, and fitted with a nozzle made of corrosion-resistant material capable of providing a solid stream and a spray pattern.

(e) The portable fire pump must be self-priming and power-driven, with—

(1) A minimum capacity of at least 300 LPM (80 gpm) at a discharge gauge pressure of not less than 414 kPa (60 psi), measured at the pump discharge;

(2) A sufficient amount of lined commercial fire-hose at least 40 mm (1.5 inches) in diameter and 15 meters (50 feet) in length, immediately available to attach to it so that a stream of water will reach any part of the vessel; and

(3) A nozzle made of corrosion-resistant material capable of providing a solid stream and a spray pattern.

(f) The pump must be stowed with its hose and nozzle outside of the machinery space.

§ 142.330 Fire detection in the engine room.

Each towing vessel must have a fire-detection system installed to detect engine room fires. A towing vessel whose construction was contracted for prior to January 18, 2000, may use an existing engine room monitoring system (with fire-detection capability) instead of a fire detection system, if the monitoring system is operable and complies with this section. The owner or managing operator must ensure that:

(a) Each detector, control panel, and fire alarm are approved under 46 CFR 161.002 or listed by an independent testing laboratory; except that, for an existing engine room monitoring system (with fire-detection capability), each detector must be listed by an independent testing laboratory.

(b) The system is installed, tested, and maintained in accordance with the manufacturer's design manual;

(c) The system is arranged and installed so a fire in the engine room automatically sets off alarms on a control panel at the primary operating station;

(d) The control panel includes:

(1) A power available light;

(2) Both an audible alarm to notify crew at the operating station of a fire, and visual alarms to identify the zone or zones of origin of the fire;

(3) A means to silence the audible alarm while maintaining indication by the visual alarms;

(4) A circuit-fault detector test-switch; and

(5) Labels for all switches and indicator lights, identifying their functions.

(e) The system draws power from two sources; switchover from the primary source to the secondary source may be either manual or automatic;

(f) The system serves no other purpose, unless it is an engine room monitoring system (with fire-detection capability) installed on a vessel whose contract for construction occurred prior to January 18, 2000; and

(g) The system is certified by a Registered Professional Engineer, or by a recognized classification society (under 46 CFR part 8), to comply with paragraphs (a) through (f) of this section.

§ 142.335 Smoke alarms in berthing spaces.

Each towing vessel must be equipped with a means to detect smoke in the berthing spaces and lounges that alerts individuals in those spaces. This may be accomplished via an installed detection system or by using individual battery-operated detectors meeting Underwriters Laboratories Standard 217 (incorporated by reference in § 142.105 of this subchapter). Detection systems or individual detectors must be kept operational at all times when the crew is onboard the towing vessel.

§ 142.340 Heat detector in galley.

Each new towing vessel equipped with a galley must have a heat detection system, which sounds an audible alarm at the operating station.

§ 142.345 Firemen's outfit.

(a) Each towing vessel 79 feet or more in length operating on oceans and coastwise routes that does not have an installed fixed fire-extinguishing system must have:

(1) At least two firemen's outfits that meet National Fire Protection Association (NFPA) 1971, Protective Ensemble for Structural Fire Fighting (incorporated by reference in § 142.115 of this subchapter).

(2) Two self-contained breathing apparatus of the pressure demand, open circuit type that are approved by the Mine Safety and Health Administration (MSHA) and by the National Institute for Occupational Safety and Health (NIOSH), under 42 CFR part 84. The breathing apparatus must have a minimum 30-minute air supply and full facepiece.

(b) [Reserved].

§ 142.350 Fire axe.

Each towing vessel must be equipped with at least one fire axe that is readily accessible for use from the exterior of the vessel.

PART 143—MACHINERY AND ELECTRICAL SYSTEMS AND EQUIPMENT

Subpart A—General

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 143.100 Purpose.

This part contains requirements for the design, installation, and operation of primary and auxiliary machinery and electrical systems and equipment on towing vessels.

§ 143.105 Applicability.

This part applies to all towing vessels subject to this subchapter.

§ 143.110 Organization of this part.

(a) Certain sections in this part contain functional requirements. Functional requirements describe the desired objective of the regulation. A towing vessel must meet the applicable functional requirements.

(b) Certain sections may also contain a prescriptive option to meet the functional requirements. A towing vessel that meets the prescriptive option will have complied with the functional requirements.

(c) If an owner or managing operator chooses to meet the functional requirement through means other than the prescriptive option, the means must be accepted by the cognizant OCMI or an approved third-party organization and documented in any TSMS applicable to the vessel.

§ 143.115 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 143.120 Incorporation by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. To enforce an edition other than that specified in paragraph (b) of this section, the Coast Guard must publish notice of the change in the **Federal Register** and the material must be available for inspection. All approved material is available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal regulations/ibr_locations.html.* Also, all materials are available at the U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street SW., Washington, DC 20593–0001, or from the sources indicated in this section.

(b) The material approved for incorporation by reference in this part and the sections affected are:

American Boat and Yacht Council (ABYC), 3069 Solomons Island Road, Edgewater, MD 21037–1416	
E–11—AC & DC Electrical Systems on Boats, 2003	143.520
H–2—Ventilation of Boats Using Gasoline, 2000	143.520
H–22—Electric Bilge Pump Systems, 2005	143.520
H–24 — Gasoline Fuel Systems, 2007	143.520
H–25—Portable Fuel Systems for Flammable Liquids, 2003	143.285, 143.520
H–32—Ventilation of Boats Using Diesel Fuel, 2004	143.520
H–33—Diesel Fuel Systems, 2005	143.520
P–1—Installation of Exhaust Systems for Propulsion and Auxiliary Engines, 2002	143.520
P–4—Marine Inboard Engines and Transmissions, 2004	143.520
American Bureau of Shipping (ABS), ABS Plaza, 16855 Northchase Drive, Houston, TX 77060	
Rules for Building and Classing Steel Vessels for Service on Rivers and Intracoastal Waterways, 2007	143,210, 143.430, 143.515, 143.535, 143.545, 143.550

Rules for Building and Classing Steel Vessels Under 90 Meters (295 Feet) in Length, 2006	143.210, 143.340, 143.430, 143.515, 143.535, 143.540, 143.545, 143.550
International Organization for Standardization (ISO), 1 rue de varembe', Case postale 56, CH–1211 Geneve 20, Switzerland	
ISO Standard 14726: 2008 Ships and marine technology—Identification colours for the content of piping systems, 2008	143.270
National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02269–9101	
NFPA 302–1998—Fire Protection Standard for Pleasure, and Commercial Motor Craft, 1998	143.285
NFPA 70–2002—National Electric Code (NEC) articles 240, 430, and 450, 2002	143.340, 143.350
Society of Automotive Engineers (SAE), 400 Commonwealth Drive, Warrendale, PA 15096–0001	
SAE J1475–1996—Hydraulic Hose Fitting for Marine Applications, 1996	143.285
SAE J1942–2005—Hose and Hose Assemblies for Marine Applications, 2005	143.285
Underwriters Laboratories, 12 Laboratory Drive, Research Triangle Park, NC 27709–3995	
UL 1104—Standards for Marine Navigation Lights, 1998	143.315

Subpart B—Requirements for All Towing Vessels

§ 143.200 Applicability.

(a) This subpart applies to all towing vessels subject to this subchapter.

(b) Where indicated, excepted towing vessels as defined in § 136.110 need not comply with the provisions of this part.

§ 143.205 Towing Safety Management System (TSMS).

If a Towing Safety Management System (TSMS) is applicable to the towing vessel, the TSMS must:

(a) Include policies and procedures to ensure compliance with this part; and

(b) Provide objective evidence that documents compliance with the TSMS.

§ 143.210 Vessels built to class.

(a) Except as noted in paragraph (b) of this section:

(1) A towing vessel classed by the American Bureau of Shipping (ABS) (incorporated by reference in § 143.120 of this part) in accordance with their rules, and as appropriate for the intended service and routes, is considered in compliance with the mechanical and electrical standards of this part.

(2) A towing vessel built and equipped to conform to ABS rules (incorporated by reference in § 143.120 of this part) appropriate for the intended service and routes, but not currently classed, may be deemed to be in compliance with this part, provided that the vessel continues to conform to ABS rules.

(b) *Additional requirements.* A towing vessel that complies with paragraph (a) of this section must also comply with the following requirements:

(1) A towing vessel that moves oil or hazardous materials in bulk must meet the class requirements described in subpart D of this part.

(2) A towing vessel must meet the potable water requirements in § 143.225 of this part.

(3) A towing vessel must meet the pilothouse alerter requirements in § 143.325 of this part.

(4) A towing vessel must meet the towing machinery requirements of § 143.330 of this part.

§ 143.215 Alternate design considerations.

Machinery or electrical equipment or systems of a novel design, unusual form, or special materials which cannot be reviewed or approved in accordance with this part, may be approved by the Commanding Officer, Marine Safety Center. It must be shown by systematic analysis, based on engineering principles, that the machinery or electrical equipment or system provides an equivalent level of safety. The owner shall submit detailed plans, material component specifications, and design criteria, including the expected vessel service and operating environment, to the Marine Safety Center.

§ 143.220 General.

(a) Machinery and electrical systems must be designed and maintained to provide for safe operation of the vessel and safety of persons onboard under normal and emergency conditions.

(b) The crew of each towing vessel must be able to demonstrate the ability to operate primary and auxiliary machinery and electrical systems under normal and emergency conditions. This includes, but is not limited to, responses to alarms and operation of propulsion and steering in the event of failure.

(c) Propulsion machinery, including main engines, reduction gears, shafting, bearings, and electrical equipment and systems, must:

(1) Be maintained to ensure proper operation;

(2) Be suitable for route and service; and

(3) Have suitable propulsion controls to provide the operator full control at the primary operating station.

(d) Repairs and minor alterations to existing towing vessels must be made in accordance with this part. New installations on or after [date after a final rule takes effect] that are not ''replacements in kind'' on an existing towing vessel must comply with subparts C and D of this part, if applicable.

§ 143.225 [Reserved]

§ 143.230 Guards for exposed hazards.

Exposed hazards, such as gears or rotating machinery, must be properly protected by a cover, guard, or rail.

§ 143.235 Machinery space fire prevention.

(a) All seals and gaskets must be properly maintained to prevent flammable liquid leaks in the machinery space.

(b) Machinery space bilges must be kept free of excessive accumulation of oil.

(c) Piping and machinery components that exceed 65.5 °C (150 °F), including fittings, flanges, valves, exhaust manifolds, and turbochargers, must be insulated. Measures must be in place to prevent flammable liquid piping leaks from coming into contact with these components.

(d) Flammable and combustible materials must not be stored in machinery spaces, unless they are stored in a suitable container that meets the requirements of § 142.225 of this subchapter.

§ 143.240 Control and monitoring requirements.

(a) Each towing vessel must have a means to monitor and control the amount of thrust, rudder angle, and (if applicable), direction of thrust at the primary operating station.

(b) Each towing vessel equipped with rudder(s) must have a means to monitor and control the position of the rudder(s) at the primary operating station.

§ 143.245 Alarms and monitoring.

(a) Each towing vessel must have a reliable means to provide notification when an emergency condition exists or an essential system develops problems that require attention. The following must be equipped with alarms:

(1) Main engine lubricating oil pressure;

(2) Main engine cooling water temperature;

(3) Main engine fuel oil pressure;

(4) Auxiliary generator engine lubricating oil pressure;

(5) Auxiliary generator engine cooling water temperature;

(6) Auxiliary generator fuel pressure;

(7) Bilge high levels;

(8) Hydraulic steering fluid levels, if applicable; and

(9) Low fuel level, if fitted with a day tank (*see* § 143.275).

(b) Alarms must:

(1) Be visible and audible at the operating station;

(2) Function when primary electrical power is lost;

(3) Have a means to test actuation at the operating station;

(4) Continue until they are acknowledged; and

(5) Not interfere with night vision at the operating station.

(c) The following systems must be equipped with gauges visible at the operating station:

(1) Main engine lubricating oil pressure;

(2) Main engine cooling water temperature;

(3) Auxiliary generator engine lubricating oil pressure;

(4) Auxiliary generator engine cooling water temperature; and

(5) Hydraulic steering fluid pressure, if the vessel is equipped with hydraulic steering systems.

(d) On excepted towing vessels, as defined in § 136.110 of this subchapter, the alarms required by this section may be located in the engine room, provided that an audible summary alarm is provided in the pilothouse and that communication exits between the pilothouse and the engine room that functions when ship service power is not available.

§ 143.250 General alarms.

(a) *Applicability.* This section applies to all towing vessels that are not an excepted vessel as defined in § 136.110 of this subchapter.

(b) *Purpose.* To provide a reliable and effective means of notifying all persons onboard the towing vessel of an emergency.

(c) Each towing vessel must be fitted with a general alarm that:

(1) Has a contact maker at the operating station that can notify persons onboard in the event of an emergency;

(2) Is capable of notifying persons in any accommodation, work space, and the engine room;

(3) Has installed, in the engine room and any other area where background noise makes a general alarm hard to hear, a supplemental flashing red light that is identified with a sign that reads: ''Attention General Alarm—When Alarm Sounds or Flashes Go to Your Station''; and

(4) Is tested at least once each week.

(d) A public-address (PA) system or other means of alerting all persons on the towing vessel may be used in lieu of the general alarm in paragraph (c) of this section if the system:

(1) Is capable of notifying persons in any accommodation, work space, and the engine room;

(2) Complies with paragraph (c)(3) of this section;

(3) Can be activated from the operating station; and

(4) Is tested at least once each week.

§ 143.255 Communication requirements.

(a) *Applicability.* This section applies to all towing vessels subject to this subchapter that are not an excepted towing vessel as defined in § 136.110 of this subchapter.

(b) *Communication system.* Each towing vessel must be fitted with a communication system between the pilothouse and the engine room that:

(1) Consists of either fixed or portable equipment, such as a sound-powered telephone, portable radios, or other reliable method of voice communication, with a main or reserve power supply that is independent of the electrical system;

(2) Provides two-way voice communication and calling between the pilothouse and either the engine room or a location immediately adjacent to an exit from the engine room.

(c) *Exceptions.* Towing vessels with more than one propulsion unit and independent pilothouse control for all engines are not required to have internal communication systems.

(d) *Direct voice communication.* When the pilothouse engine controls and the access to the engine room are within 3 meters (10 feet) of each other and allow unobstructed visible contact between them, direct voice communication is acceptable instead of a communication system.

§ 143.260 Readiness and testing.

(a) *Functional requirements.* Essential systems or equipment must be regularly tested and examined. If a component is found unsatisfactory, it must be repaired or replaced. Test and examination procedures must be in accordance with manufacturer's instructions (if available) and the vessel's Towing Safety Management System, if the vessel has a TSMS. Tests and examinations must verify that the system or equipment functions as designed.

(b) *Prescriptive option.* The towing vessel must perform the tests in Table 143.260(c) of this section. The tests required by this section must be recorded in accordance with part 140 of this subchapter.

TABLE 143.260(c)—REQUIRED TESTS AND FREQUENCY

Tests of:	Frequency
Propulsion controls; ahead and astern at the operating station	Before the vessel embarks on a trip or voyage of more than 24 hours or when each new master takes command.
Steering controls at the operating station	Before the vessel embarks on a trip or voyage of more than 24 hours or when each new master takes command.
Pilothouse alerter system required by § 143.325 of this part, as applicable.	Weekly.
All alternate steering and propulsion controls including those required by subpart D of this part (if applicable).	Weekly.

TABLE 143.260(c)—REQUIRED TESTS AND FREQUENCY—Continued

Tests of:	Frequency
Alarm actuation circuits for alarms required by § 143.245 of this part, and if applicable, subpart D of this part.	Weekly.
Emergency communication, including any required by subpart D if applicable.	Weekly.
General alarm if the vessel is so equipped	Weekly.
Emergency lighting and power if the vessel is so equipped	At least once every 3 months.
Storage batteries if the vessel is so equipped, for emergency lighting and power.	At least once every 3 months.
Alarm setpoints	Annually using methods described in 46 CFR 61.40–10.
Pressure vessel safety valves	Annually.
All other essential systems	At least once every 3 months.

§ 143.270 System isolation and markings.

Electrical equipment, piping for flammable liquid, seawater cooling, or firefighting systems must be provided with isolation devices and markings as follows:

(a) Electrical equipment must be provided with circuit isolation and must be marked as described in § 143.305 of this part;

(b) Electrical panels or other enclosures containing more than one source of power must be fitted with a sign warning persons of this condition and identifying where to secure all sources;

(c) Piping for flammable liquid, seawater cooling, or firefighting systems must be fitted with isolation valves that are clearly marked by labeling or color coding that enables the crew to identify its function; and

(d) Any piping system that penetrates the hull below the waterline must be fitted with efficient and accessible means, located as close to the hull penetrations as is practicable, for preventing the accidental admission of water into the vessel either through such pipes or in the event of a fracture of such pipe. The valve must be clearly marked by labeling or color coding that enables the crew to identify its function.

(e) Color coding required by this section may be met by complying with coding standards contained in International Organization for Standardization (ISO) standard 14726 (incorporated by reference in § 143.120 of this part), or in accordance with the Towing Safety Management System applicable to the vessel.

§ 143.275 Fuel system requirements for towing vessels.

(a) Fuel systems for the towing vessel, main engine propulsion, and auxiliary generator systems must be maintained to ensure proper operation of the system.

(b) A continuous supply of clean fuel must be provided to all engines necessary for towing vessel control including the main propulsion engines and auxiliary generator engines.

(c) The fuel system must include filters or centrifuge. Where filters are used:

(1) A supply of spare fuel filters must be provided onboard; and

(2) Fuel filters must be examined and replaced in accordance with manufacturer's requirements.

(d) Towing vessels equipped with a day tank must be equipped with a low fuel level alarm that meets the requirements of § 143.245 of this part.

§ 143.280 Fuel shutoff requirements.

(a) *Applicability.* This section applies to all towing vessels subject to this subchapter that are not excepted towing vessels, as defined in § 136.110 of this subchapter.

(b) To stop the flow of fuel in the event of a break in the fuel line, a positive, remote fuel shutoff valve must be fitted on any fuel line that supplies fuel directly to an engine or generator prime mover.

(c) The valve must be near the source of supply (for instance, at the day tank, storage tank, or fuel-distribution manifold).

(d) The valve(s) must be operable from a safe place outside the space where the valve is installed.

(e) Each remote valve control should be marked in clearly legible letters, at least 25 millimeters (1 inch) high, indicating the purpose of the valve and the way to operate it.

§ 143.285 Additional fuel system requirements for towing vessels built after January 18, 2000.

(a) *Applicability.* This section applies to all towing vessels subject to this subchapter that are not excepted towing vessels, as defined in § 136.110 of this subchapter. Except for the components of an outboard engine or of a portable bilge or fire pump, each fuel system installed onboard the towing vessel must comply with this section.

(b) *Portable fuel systems.* The towing vessel must not incorporate or carry portable fuel systems, including portable tanks and related fuel lines and accessories, except when used for outboard engines or when permanently attached to portable equipment such as portable bilge or fire pumps. The design, construction, and stowage of portable tanks and related fuel lines and accessories must comply with the American Boat and Yacht Council (ABYC) H–25 (incorporated by reference in § 143.120 of this subchapter).

(c) *Vent pipes for integral fuel tanks.* Each integral fuel tank must meet the following:

(1) Each tank must have a vent that connects to the highest point of the tank, discharges on a weather deck through a bend of 180 degrees (3.14 radians), and is fitted with a 30-by-30-mesh corrosion-resistant flame screen. Vents from two or more fuel tanks may combine in a system that discharges on a weather deck. The net cross-sectional area of the vent pipe for the tank must be not less than 312.3 square millimeters (0.484 square inches), for any tank filled by gravity, but not less than that of the fill pipe for any tank filled under pressure.

(d) *Fuel piping.* Except as permitted in paragraphs (e)(1), (2), and (3) of this section, each fuel line must be seamless and made of steel, annealed copper, nickel-copper, or copper-nickel. Each fuel line must have a wall thickness of not less than 0.9 millimeters (0.035 inch) except that—

(1) Aluminum piping is acceptable on an aluminum-hull vessel if it is installed outside the engine room and is at least Schedule 80 in thickness; and

(2) Nonmetallic flexible hose is acceptable if it—

(i) Is used in lengths of not more than 0.76 meters (30 inches);

(ii) Is visible and easily accessible;

(iii) Does not penetrate a watertight bulkhead;

(iv) Is fabricated with an inner tube and a cover of synthetic rubber or other suitable material reinforced with wire braid; and

(v) Either,—

(A) If it is designed for use with compression fittings, is fitted with suitable, corrosion-resistant, compression fittings, or fittings compliant with Society of Automotive Engineers (SAE) J1475 (incorporated by reference in § 143.120 of this subchapter); or

(B) If it is designed for use with clamps, is installed with two clamps at each end of the hose. Clamps must not rely on spring tension and must be installed beyond the bead or flare or over the serrations of the mating spud, pipe, or hose fitting. Hose complying with SAE J1475 (incorporated by reference in § 143.120 of this subchapter), is also acceptable.

(3) Nonmetallic flexible hose complying with SAE J1942 (incorporated by reference in § 143.120 of this subchapter), is also acceptable.

(e) A towing vessel of less than 79 feet in length may comply with any of the following standards for fuel systems instead of those of paragraph (d) in this section:

(1) American Boat and Yacht Council (ABYC) H–33 (incorporated by reference in § 143.120 of this part);

(2) Chapter 5 of National Fire Protection Association (NFPA) 302 (incorporated by reference in § 143.120 of this part); or

(3) 33 CFR chapter I, subchapter S (Boating Safety).

§ 143.290 Piping systems and tanks.

Vessel piping and tanks that are exposed to the outside of the hull must be made of metal and maintained in a leak free condition.

§ 143.295 Bilge pumps or other dewatering capability.

Each towing vessel must have an installed bilge pump or another method for emergency dewatering, such as a portable pump with sufficient hose length. All bilge piping, whether installed or portable, must have a check/foot valve in each bilge suction that prevents unintended backflooding through bilge piping.

§ 143.300 Pressure vessels.

(a) Pressure vessels over 5 cubic feet in volume and over 15 PSI maximum allowable working pressure must be equipped with an indicating pressure gage (in a readily visible location) and with one or more spring-loaded relief valves. The total relieving capacity of such relief valves must be such as to prevent pressure in the receiver from exceeding the maximum allowable working pressure of the receiver, as established by the manufacturer, by more than 10 percent.

(b) Compressed air receivers must be examined and relief valves must be tested at least annually.

(c) Pressure vessels installed after [EFFECTIVE DATE OF FINAL RULE] must meet the requirements of § 143.540 of this part.

§ 143.305 Electrical systems, general.

(a) Electrical systems and equipment on board towing vessels must function properly and minimize system failures, fire hazards, and shock hazards to personnel.

(b) Installed electrical power source(s) must be capable of carrying the electrical load of the towing vessel under normal operating conditions.

(c) Electrical equipment must be marked with its respective current and voltage ratings.

(d) All panels, motors, and major electrical equipment must be marked with the location(s) of the designated isolating switch or circuit breaker. Individual circuit breakers on switchboards and distribution panels must be labeled with a description of the loads they serve.

(e) Electrical connections must be suitably installed to prevent them from coming loose through vibration or accidental contact.

(f) Electrical equipment and electrical cables must be suitably protected from wet and corrosive environments.

(g) Electrical components that pose an electrical hazard must be in an enclosure.

(h) Electrical conductors passing though watertight bulkheads must be installed so that the bulkhead remains watertight.

(i) When flexible cable is used to transmit power between the vessel and tow:

(1) The receptacles must be male and the flexible cable leads must be female; and

(2) The connection must be designed to prevent unintended separation.

§ 143.310 Shipboard lighting.

(a) Sufficient lighting suitable for the marine environment must be provided on towing vessels within crew working and living areas.

(b) Emergency lighting must be provided for all crew working and living areas internal to the towing vessel. Emergency lighting sources must provide for sufficient illumination under emergency conditions to facilitate egress from each space and must be either:

(1) Powered as described in § 143.340(b)(9) of this part;

(2) Automatic, battery-operated with a duration of no less than 3 hours; or

(3) Non-electric, phosphorescent adhesive lighting strips that are installed along escape routes and sufficiently visible to enable egress with no power.

(c) Each towing vessel must be equipped with at least two operable, portable, and battery-powered lights. One must be located in the pilothouse and the other at the access to the engine room.

§ 143.315 Navigation lights.

(a) Towing vessels more than 65 feet in length must use navigation lights that meet Underwriters Laboratories (UL) 1104 (incorporated by reference in § 143.120 of this part) or other standards specified by the Coast Guard.

(b) Towing vessels 65 feet or less in length may meet the requirements listed in 33 CFR 183.810 or paragraph (a) of this section.

Subpart C—Deferred Requirements for Existing Towing Vessels

§ 143.320 Applicability.

(a) This section applies to existing towing vessels, as defined in § 136.110 of this subchapter, that are not excepted towing vessels.

(b) A towing vessel to which this section applies need not comply with the requirements of this subpart until 5 years after the issuance of its first Certificate of Inspection (COI).

(c) Repairs and minor alterations to existing towing vessels must be made in accordance with Subpart B of this part. New installations on or after the date of issuance of the existing towing vessel's first (COI) that are not ''replacements in kind'' on that vessel must comply with subparts C and (if applicable) D of this part.

§ 143.325 Pilothouse alerter system.

(a) A towing vessel with overnight accommodations and alternating watches (shift work), when pulling, pushing or hauling along side one or more barges, must have an alarm to detect when its master or mate (pilot) becomes incapacitated. The alarm must:

(1) Have a method to detect possible incapacitation of the master and actuate in the pilothouse when this condition exists;

(2) Require acknowledgement in the pilothouse within 10 minutes;

(3) If not acknowledged within 10 minutes, promptly notify another crewmember; and

(4) Be distinct from any other alarm.

(b) A towing vessel need not comply with this section if a second person is provided in the pilothouse.

§ 143.330 Towing machinery.

(a) Towing machinery such as capstans, winches, and other mechanical devices used to connect the towing vessel to the tow must be designed and installed to maximize control of the tow.

(b) Towing machinery for towing astern must have sufficient safeguards to prevent the machinery from becoming disabled in the event the tow becomes out of line.

(c) Towing machinery used to connect the towing vessel to the tow must be suitable for its intended service. It must be capable of withstanding exposure to the marine environment, likely mechanical damage, static and dynamic loads expected during intended service, the towing vessel's horsepower, and arrangement of the tow.

(d) When a winch is used that has the potential for uncontrolled release under tension, a warning must be in place at the winch controls that indicates this. When safeguards designed to prevent uncontrolled release are utilized, they must not be disabled.

(e) Each owner or managing operator must develop procedures to routinely examine, maintain, and replace capstans, winches, and other machinery used to connect the towing vessel to the tow.

§ 143.335 Remote shutdowns.

(a) Each towing vessel must have a remote manual shutdown for each main propulsion engine and auxiliary generator engine, which can be operated from a location outside the machinery space where the engines are located.

(b) The fuel shutoff required by § 143.280(b) of this part may serve as the remote manual shutdown, provided each engine can be independently shutdown.

§ 143.340 Electrical power sources, generators, and motors.

(a) *Functional Requirements.* (1) Each towing vessel must have sufficient electrical power to provide for the applicable power needs for:

(i) Propulsion, steering and control systems;

(ii) Safety systems;

(iii) Navigation systems;

(iv) Control of the tow;

(v) Minimum conditions of habitability; and

(vi) Other installed or portable systems and equipment.

(2) Generators and motors must be suitably rated for the environment where they operate, marked with their respective ratings, and suitably protected against overcurrent.

(3) In the event of a main power source failure, a towing vessel, other than an excepted towing vessel, must have a means to power essential alarms, lighting, radios, navigation equipment, and any other essential system identified by an approved third party or the cognizant Officer in Charge, Marine Inspection (OCMI).

(b) *Prescriptive option to meet functional requirements.* (1) The owner or managing operator of each towing vessel must complete a load analysis that shows that the electrical power source is sufficient to power the sum of connected loads described in paragraph (a)(1) of this section utilizing an appropriate load factor for each load.

(2) Prior to implementation of this section, the owner or managing operator must complete the load analysis of paragraph (b)(1) of this section. A record of the analysis must be retained by the owner or managing operator and be available upon request of the approved third party or cognizant OCMI.

(3) The owner or managing operator must have procedures for the evaluation of additional electrical loads added to the towing vessel to ensure compliance with paragraph (a)(1) of this section.

(4) Installed generators or motors must have a data plate listing rated kilowatts and power factor (or current), voltage, and ambient temperature.

(5) Generators must be provided with overcurrent protection no greater than 115 percent of their rated current and utilize a distribution panel.

(6) Motors must be provided with overcurrent protection that meets article 430 of the National Electric Code (NEC) (incorporated by reference in § 143.120 of this subchapter). Steering motor circuits must be protected as per Part 4 Chapter 6 Section 2, Regulation 11 (except 11.7) of American Bureau of Shipping (ABS) Rules for Building and Classing Steel Vessels Under 90 Meters (295 feet) in Length, (incorporated by reference in § 143.120 of this part).

(7) Generators and motors installed in machinery spaces must be certified to operate in an ambient temperature of 50°C unless they are derated. When derating, divide the rated ambient temperature of the generator (in degrees Celsius) by 50°C and multiply the resulting factor by the maximum rated current of the generator. Each generator and motor, except a submersible-pump motor, must be in an accessible space which is adequately ventilated and as dry as practicable. It must be mounted above the bilges to avoid damage by splash and to avoid contact with low-lying vapors.

(8) A generator driven by a main propulsion unit (such as a shaft generator) which is capable of providing electrical power continuously, regardless of the speed and direction of the propulsion shaft, may be considered one of the power sources required by paragraph (a) of this section. Any vessel speed change or throttle movement must not cause electrical power interruption.

(9) Other than excepted towing vessels, each towing vessel that relies on electricity for power must be arranged so that the following loads can be energized from two independent sources of electricity:

(i) Alarms required by § 143.245 of this part;

(ii) Emergency egress lighting, unless the requirements of § 143.310(b)(2) or (3) of this part are met;

(iii) Navigation lights;

(iv) Pilothouse lighting;

(v) Any installed radios and navigation equipment; and

(vi) Any essential system identified by an approved third party or the cognizant Officer in Charge, Marine Inspection.

(vii) If a battery is used as the second source of electricity required of this subsection, it must be capable of supplying the loads for at least three hours.

§ 143.345 Electrical distribution panels and switchboards.

(a) Each distribution panel or switchboard on a towing vessel must be:

(1) In a location that is accessible, as dry as practicable, adequately ventilated, and protected from falling debris and dripping or splashing water;

(2) Totally enclosed and of the dead-front type; and

(3) Fitted with a drip shield, unless the switchboard or distribution panel is of a type mounted deck-to-overhead and is not subject to falling objects or liquids from above.

(b) Each switchboard accessible from the rear must be constructed to prevent a person's accidental contact with energized parts.

(c) Nonconductive mats or grating must be provided on the deck in front of each switchboard and, if it is accessible from the rear, on the deck behind the switchboard.

(d) Each un-insulated current-carrying part must be mounted on noncombustible, nonabsorbent, and high-dielectric insulating material.

(e) Equipment mounted on a hinged door of an enclosure must be constructed or shielded so that a person will not come into accidental contact with energized parts of the door-mounted equipment when the door is open and the circuit energized.

§ 143.350 Electrical overcurrent protection other than generators and motors.

(a) *Functional requirement.* Power and lighting circuits on towing vessels must be protected by suitable overcurrent protection. On a towing vessel, other than an excepted towing vessel as defined in § 136.110 of this subchapter, an overcurrent protection device must not be used for both essential and non-essential systems.

(b) *Prescriptive option to meet functional requirements.* (1) Cable and wiring used in power and lighting circuits must be protected by overcurrent protection that opens the circuit at the standard setting closest to 80 percent of the manufacturer's listed ampacity. Overcurrent protection setting exceptions allowed by the National Electric Code (NEC), Article 240 (incorporated by reference in § 143.120 of this subchapter) may be employed.

(2) If the manufacturer's listed ampacity is not known, table 310.16 of the NEC (incorporated by reference in § 143.120 of this part) must be used, assuming a temperature rating of 75 degrees and an assumed temperature of 50 degrees Celsius for machinery spaces and 40 degrees for other spaces.

(3) Overcurrent protection devices must be installed in a manner that will not open the path to ground in a circuit; only ungrounded conductors must be protected. Overcurrent protection must be coordinated such that an overcurrent situation is cleared by the nearest circuit breaker or fuse.

(4) Each transformer must have protection against overcurrent that meets article 450 of the NEC (incorporated by reference in § 143.120 of this part).

(5) On a towing vessel, other than an excepted vessel as defined in § 136.110 of this subchapter, essential systems and non-essential systems must not be on the same circuit or share the same overcurrent protective device.

§ 143.355 Electrical grounding and ground detection.

(a) Dual voltage electrical distribution systems on towing vessels must have the neutral suitably grounded. There must be only one connection to ground, regardless of the number of power sources. This connection must be at the main switchboard or distribution panel.

(b) On a metallic towing vessel, a grounded distribution system must be grounded to the hull. This grounded system must be connected to a common, non-aluminum ground plate. The ground plate must have only one connection to the main switchboard or distribution panel, and the connection must be readily accessible for examination.

(c) On a nonmetallic towing vessel, all electrical equipment must be grounded to a common ground. Multiple ground plates bonded together are acceptable.

(d) Each insulated grounding-conductor of a cable must be identified by one of the following means:

(1) Wrapping the cable with green braid or green insulation;

(2) Stripping the insulation from the entire exposed length of the grounding-conductor; or

(3) Marking the exposed insulation of the grounding-conductor with green tape or green adhesive labels.

(e) A towing vessel's hull may not carry current as a conductor, except for an impressed-current cathodic-protection system or a battery system to start an engine.

(f) Cable armor may not be used to ground electrical equipment or systems.

(g) Each receptacle outlet and attachment plug for a portable lamp, tool, or similar apparatus operating at 100 or more volts must have a grounding-pole and a grounding-conductor in the portable cord.

(h) In a grounded distribution system, only grounded, three-prong appliances may be used. Adaptors that allow an ungrounded, two-prong appliance to fit into a grounded, three-prong, receptacle must not be used.

(i) A suitable method must be in place to detect unintentional grounds.

§ 143.360 Electrical conductors, connections, and equipment.

(a) Each cable and wire on a towing vessel must:

(1) Have conductors with sufficient current-carrying capacity for the circuit in which it is used;

(2) Be suitably supported every 24 inches with metal supports and not installed with sharp bends;

(3) Be installed in a manner to prevent contact with personnel, mechanical hazards, and hazards from leaking fluids and must not be installed in bilges, locations where a piping leak would drip on them, across a normal walking path, or less than 24 inches from moving machinery;

(4) Have connections and terminations suitable for copper stranded conductors that retain the original electrical, mechanical, flame-retarding, and where necessary, fire-resisting properties of the conductor. If twist-on types of connectors are used, the connections must be made within an enclosure and the insulated cap of the connector must be secured to prevent loosening due to vibration. Twist-on type of connectors may not be used for making joints in cables, facilitating a conductor splice, or extending the length of a circuit;

(5) Be installed so as to avoid or reduce interference with radio reception and compass indication;

(6) Be protected from the weather;

(7) Be supported in order to avoid chafing or other damage;

(8) Be protected by metal coverings or other suitable means, if in areas subject to mechanical abuse;

(9) Be suitable for low temperature and high humidity, if installed in refrigerated compartments;

(10) Be located outside a tank, unless it supplies power to equipment in the tank; and

(11) If wire is installed in a tank, it must have sheathing or wire insulation compatible with the fluid in a tank.

(b) Extension cords may not be used as a permanent source of electrical power.

(c) Multi-outlet adapters may not be used to expand the capacity of a receptacle.

Subpart D—Requirements for Towing Vessels That Tow Oil or Hazardous Materials in Bulk

§ 143.400 General applicability.

This subpart applies to a towing vessel subject to this subchapter that moves barges carrying oil or hazardous materials in bulk.

(a) An existing towing vessel need not comply with the requirements of this subpart until 5 years after the issuance of its first Certificate of Inspection (COI).

(b) An excepted towing vessel, as defined in § 136.110 of this subchapter, is not required to comply with the requirements of this subpart.

§ 143.405 General requirements for propulsion, steering, and related controls.

(a) A towing vessel to which this subpart applies must have an alternate means to control the propulsion and steering system which shall:

(1) Be independent of the primary control required by § 143.240 of this part;

(2) Be located at or near the propulsion and steering equipment; and

(3) Be readily accessible and suitable for prolonged operation.

(b) A towing vessel to which this subpart applies must have a means to communicate between the operating station and the alternate propulsion and steering controls.

(c) A towing vessel to which this subpart applies must have a means to stop each propulsion engine and steering motor from the operating station.

(d) The means to monitor the amount of thrust, rudder angle, and (if applicable) direction of thrust must be independent of the controls required by § 143.240 of this part.

(e) The propulsion control system required by § 143.240 of this part must be designed so that, in the event of a single failure of any component of the system, propeller speed and direction of thrust are maintained or reduced to zero.

(f) On a towing vessel with an integrated steering and propulsion system, such as a Z-drive, the control system required by § 143.240 of this part must be designed so that, in the event of a single failure of any component of the system, propeller speed and direction of thrust are maintained or the propeller speed is reduced to zero.

(g) An audible and visual alarm must actuate at the operating station when:

(1) The propulsion control system fails;

(2) A non-follow up steering control system fails, if installed; and

(3) The ordered rudder angle does not match the actual rudder position on a follow-up steering control system, if installed. This alarm must have an appropriate delay and error tolerance to eliminate nuisance alarms.

(h) Alarms must be separate and independent of the control system required by § 143.240 of this part and function when primary electrical power is lost.

(i) A means of communication must be provided between the operating station and any crewmember(s) required to respond to alarms.

(j) The two sources of electricity required by § 143.340(a)(3) and (b)(9) of this part must be capable of powering electrical loads needed to maintain propulsion, steering, and related controls for not less than 3 hours.

(k) A towing vessel to which this subpart applies that uses propulsion, steering, or related controls that are directly reliant on electrical power, must have a means to automatically restore power to propulsion, steering, and related controls when the main power source fails.

(l) A towing vessel to which this subpart applies that uses propulsion, steering, or related controls that are directly reliant on stored energy, such as air or hydraulics, must:

(1) Have two independent, stored energy systems capable of maintaining propulsion, steering, and related controls; and

(2) If the stored energy system is recharged by electrical power, have sufficient stored energy available to provide time to switch electrical power sources without a loss of propulsion, steering, or related controls.

(m) After a power failure, electrical motors used to maintain propulsion and steering must automatically restart when power is restored, unless remote control starting is provided at the operating station.

§ 143.410 Propulsor redundancy.

(a) A towing vessel must be provided with at least two independent propulsors unless the requirements of § 143.420 are met.

(b) There must be independent controls for each propulsor at the operating station.

(c) In the event of a failure of a single propulsor, the remaining propulsor(s) must have sufficient power to maneuver the vessel to a safe location.

§ 143.420 Vessels with one propulsor.

(a) A towing vessel must have independent, duplicate vital auxiliaries. For the purpose of this section, vital auxiliaries are the equipment necessary to maintain the propulsion engine (*e.g.,* fuel, lubricating oil, and cooling pumps). In the event of a failure or malfunction of any single vital auxiliary, the propulsion engine must continue to provide propulsion adequate to maintain control of the tow.

(b) In the event of a failure, the corresponding independent duplicate vital auxiliary, described in paragraph (a) of this section, must automatically assume the operation of the failed unit.

(c) Propulsion engine fuel line(s) must meet the requirements of § 143.285, regardless of build date.

(d) A towing vessel must be provided with an independent, auxiliary steering system that:

(1) Has independent controls available at the operating station;

(2) Is immediately available upon the loss of main steering system;

(3) Is appropriate to maneuver the tow; and

(4) Remains operable in the event of any single failure that affects the main steering system. This does not apply to failures of the tiller, quadrant, or other equipment that serve the same purpose.

(e) For the purpose of this section, the place where isolation valves join the piping system, as by a flange, constitutes a single-failure point. The valve itself need not constitute a single-failure point if it has a double seal to prevent substantial loss of fluid under pressure.

§ 143.430 Alternative standards.

(a) In lieu of meeting this subpart, a towing vessel may comply with the American Bureau of Shipping (ABS) Steel rules for vessels under 90 meters (incorporated by reference in § 143.120 of this part) as follows:

(1) Sections 4–7–5 (class ACBU) and 4–3–5 (class R2); and

(2) A vessel that operates exclusively on rivers or intracoastal waterways need not meet 4–7–4/3.9 and the automatic day tank fill pump requirement of 4–7–4/25.3.

(b) A vessel meeting the alternative standards of this section must comply with § 143.435 of this subpart.

§ 143.435 Demonstration of compliance.

(a) The owner or managing operator of each towing vessel must devise test procedures that demonstrate compliance with the design and engineering requirements prescribed in this subpart.

(b) The tests required in paragraph (a) of this section must be satisfactorily conducted and witnessed by an approved third party or cognizant Officer in Charge, Marine Inspection (OCMI) prior to implementation date of this section. A record of the test must be retained by the owner or managing operator and be available upon request of the approved third party or cognizant OCMI.

Subpart E—New Towing Vessels

§ 143.500 Applicability.

This subpart applies to a new towing vessel, as defined in § 136.110 of this subchapter, unless it is an excepted vessel.

§ 143.505 Standards to be used.

(a) Except as noted in paragraph (b) of this section, a new towing vessel must be constructed using the standards specified in this part. The standard selected must be used in its entirety.

(b) An alternate standard may be considered by the Commanding Officer, Marine Safety Center where it can be shown that it provides an equivalent level of safety and performance.

§ 143.510 Plan approval.

Procedures for plan approval are contained in part 144 of this subchapter.

§ 143.515 Towing vessels built to American Bureau of Shipping rules.

(a) Except as noted in paragraph (b) of this section:

(1) A towing vessel classed by the American Bureau of Shipping (ABS) (incorporated by reference in § 143.120 of this part) in accordance with their rules as appropriate for the intended service and routes is considered in compliance with this subpart.

(2) A towing vessel built and equipped to conform to ABS

(incorporated by reference in § 143.120 of this subchapter) rules appropriate for the intended service and routes, but not currently classed, may be deemed to be in compliance with this subpart providing it can be shown that the vessel continues to conform to ABS rules.

(b) In addition to the requirements in paragraph (a) of this section, a new towing vessel:

(1) That moves barges carrying oil or hazardous materials in bulk must meet the class requirements described in § 143.430 of this part.

(2) Must meet the potable water requirements in § 143.530 of this part.

(3) Must meet the pilothouse alerter requirements in § 143.325 of this part.

(4) Must meet the towing machinery requirements of § 143.330 of this part.

§ 143.520 Towing vessels built to American Boat and Yacht Council (ABYC) standards.

(a) Except as noted in paragraph (b) of this section, a new towing vessel 65 feet (19.8 meters) or less in length built to conform with the American Boat and Yacht Council (ABYC) standards listed in this paragraph (Incorporated by reference in § 143.120 of this subchapter) is considered in compliance with this subpart.

(1) H–2–Ventilation of Boats Using Gasoline;

(2) H–22—Electric Bilge Pump Systems;

(3) H–24—Gasoline Fuel Systems;

(4) H–25—Portable Gasoline Fuel Systems for Flammable Liquids;

(5) H–32—Ventilation of Boats Using Diesel Fuel;

(6) H–33—Diesel Fuel Systems;

(7) P–1—Installation of Exhaust Systems for Propulsion and Auxiliary Engines; and

(8) P–4—Marine Inboard Engines and Transmissions

(9) ABYC E–11—AC & DC Electrical Systems on Boats.

(b) In addition to the requirements in paragraph (a) of this section, a new towing vessel 65 feet (19.8 meters) or less in length must meet the:

(1) Requirements of subpart B of this part;

(2) Requirements described in subpart D of this part if it moves oil or hazardous materials in bulk;

(3) Potable water requirements in § 143.530 of this part;

(4) Pilothouse alerter requirements in § 143.325 of this part; and

(5) Towing machinery requirements of § 143.330 of this part.

§ 143.525 Towing vessels not built to American Bureau of Shipping (ABS) rules or American Boat and Yacht Council (ABYC) standards.

A new towing vessel not built to American Bureau of Shipping rules or American Boat and Yacht Council standards must meet subparts B and C of this part and §§ 143.530 through 143.555 of this subpart.

§ 143.530 [Reserved]

§ 143.532 New towing vessels that move barges carrying oil or hazardous materials in bulk.

A new towing vessel that moves barges carrying oil or hazardous materials in bulk must meet the requirements in subpart D of this part.

§ 143.535 Pumps, pipes, valves, and fittings for essential systems.

(a) In lieu of meeting the requirements of § 143.285 of this part, a new towing vessel must meet the requirements of this section.

(b) Except as noted in paragraph (c) of this section pumps, pipes, valves, and fittings in essential systems on vessels must meet American Bureau of Shipping (ABS) rules for Steel Vessels under 90 Meters (incorporated by reference in § 143.120 of this part), Part 4, Chapter 4 as applicable.

(c) Pumps, pipes, valves, and fittings in essential systems on towing vessels operating exclusively on rivers or intracoastal waterways may meet ABS Rules for Steel Vessel on Rivers and Intracoastal Waterways (incorporated by reference in § 143.120 of this subchapter), Part 4, Chapter 3 as applicable in lieu of paragraph (b) of this section.

§ 143.540 Pressure vessels.

(a) In lieu of meeting the requirements of § 143.300 of this part, a new towing vessel must meet the requirements of this section.

(b) Pressure vessels over 5 cubic feet in volume and over 15 pounds per square inch maximum allowable working pressure on new towing vessels must meet American Bureau of Shipping Rules for Steel Vessels under 90 Meters (incorporated by reference in § 143.120 of this part), Part 4, Chapter 1, Section 1, Regulation 7.5.

§ 143.545 Steering systems.

(a) Except as noted in paragraph (b) of this section, steering systems on new towing vessels must meet American Bureau of Shipping (ABS) rules for Steel Vessels under 90 Meters (incorporated by reference in § 143.120 of this part), section 4–3–3, as applicable.

(b) Steering systems on new towing vessels operating exclusively on rivers or intracoastal waterways may meet ABS Rules for Steel Vessels on Rivers and Intracoastal Waterways (incorporated by reference in § 143.120 of this part), section 4–2–3 as applicable, in lieu of paragraph (a) of this section.

§ 143.550 Electrical installations.

(a) In lieu of meeting the requirements of §§ 143.340–360 of this part, a new towing vessel must meet the requirements of this section.

(b) Except as noted in paragraph (c) of this section, electrical installations on vessels must meet American Bureau of Shipping (ABS) Rules for Steel Vessels Under 90 Meters (incorporated by reference in § 143.120 of this part), chapter 4–6.

(c) Electrical installations on vessels operating exclusively on rivers or intracoastal waterways may meet ABS Rules for Steel Vessels on Rivers and Intracoastal Waterways (incorporated by reference in § 143.120 of this part), Part 4, Chapter 5 in lieu of paragraph (a) of this section.

PART 144—CONSTRUCTION AND ARRANGEMENT

Subpart A–General

Subpart B—All Towing Vessels

Subpart C—Existing Towing Vessels

Subpart D—New Towing vessels

Authority: 46 U.S.C. 3103, 3301, 3306, 3308, 3316, 8104, 8904; 33 CFR 1.05; DHS Delegation 0170.1.

Subpart A—General

§ 144.100 Purpose.

This part details the requirements for design, construction and arrangement, and plan review and approval for towing vessels.

§ 144.105 Definitions.

The definitions provided in § 136.110 of this subchapter apply to this part.

§ 144.110 Incorporation by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the Coast Guard must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.* Also, it is available for inspection at U.S. Coast Guard, Office of Design and Engineering Standards (CG–521), 2100 Second Street SW., Washington, DC 20593–0001, and is available from the sources listed in paragraph (b) of this section.

(b) The material approved for incorporation by reference in this part and the sections affected are:

American Bureau of Shipping (ABS), ABS Plaza, 16855 Northchase Drive, Houston, TX 77060	
Rules for Building and Classing Steel Vessels for Service on Rivers and Intracoastal Waterways, 2007	144.410
Rules for Building and Classing Steel Vessels Under 90 Meters (295 Feet) in Length, 2006	144.410
International Maritime Organization, (IMO). 4 Albert Embankment, London SE1 7SR	
Resolution A.688(17) Fire Test Procedures For Ignitability of Bedding Components, 1991	144.435

Subpart B—All Towing Vessels

§ 144.200 Applicability.

This subpart applies to all towing vessels subject to this subchapter.

§ 144.205 Towing Safety Management System (TSMS).

If a Towing Safety Management System (TSMS) is applicable to the vessel, the TSMS must:

(a) Include policies and procedures to ensure compliance with this part; and

(b) Provide objective evidence that documents compliance with the TSMS.

§ 144.210 General.

The construction and arrangement of the towing vessel must be suitable for the service and route of the vessel, including the welfare of the crew and control of the tow.

§ 144.215 Special consideration.

The cognizant Officer in Charge, Marine Inspection may give special consideration to the structural requirements for small vessels or vessels of an unusual design not contemplated by the rules of the American Bureau of Shipping or other recognized classification society.

§ 144.220 Verification of compliance.

A verification of compliance with established standards must be performed as follows:

(a) Prior to conducting a major conversion or alternation to the hull, machinery, or equipment that affect the safety of a new or existing towing vessel;

(b) For new installations, after [date final rule takes effect], that are not ''replacements in kind'' on an existing towing vessel; and

(c) Upon request of the Coast Guard.

§ 144.225 Qualifications.

(a) Verification of compliance with this part must be performed by a registered Professional Engineer (P.E.) licensed by one of the 50 states of the United States or the District of Columbia, or by a current, full time employee of the American Bureau of Shipping (ABS).

(b) The P.E. must ensure that he or she does not exceed the scope of his or her P.E. license.

(c) In the case of certifications by ABS employees, ABS must ensure the reviewer holds proper ABS qualifications for the particular type of review being conducted.

§ 144.230 Procedures for verification of compliance with construction and arrangement standards.

(a) Verification of compliance with construction and arrangement standards for towing vessels, when required, must be performed by an individual meeting the requirements of § 144.225 of this part.

(b) Objective evidence of compliance must be provided to the Coast Guard and include:

(1) A description of the towing vessel's intended service and route;

(2) The standards applied;

(3) Deviations from the standards used;

(4) A statement that the towing vessel is suitable for the intended service and route;

(5) The name, address, employer affiliation, license number, and state of licensure of the professional engineer making the verification; and

(6) Attestation by the builder that the vessel was built to plans.

(c) The verification must include a review and analyses of sufficient plans, drawings, schematics, and calculations to ensure the vessel complies with the standards used. The plans must be stamped or otherwise indicate that they have been reviewed by an individual meeting the requirements of § 144.225.

(d) A copy of the verified plans must be forwarded to the cognizant Officer in Charge, Marine Inspection in whose zone the work will be performed.

(e) A copy of the verified plans must be available at the construction site.

(f) Plans reviewed and approved by the American Bureau of Shipping need not be forwarded to the Coast Guard unless requested.

§ 144.235 Verification for sister vessels.

(a) A full verification of compliance is not required for sister towing vessels, provided that:

(1) The plans for the original vessels have already been verified as complying with this part;

(2) The owner authorizes their use for the new construction;

(3) The regulations or published standards have not changed since the original verification;

(4) The sister vessel is built to the same plans and equipped with the same machinery as the first vessel of the class, and has not been subsequently modified;

(5) The sister vessel is built in the same shipyard facility as the first vessel;

(6) For stability purposes, the sister vessel is delivered within 2 years of the stability test date of an earlier vessel in the class. If delivered later than 2 years, the sister vessel must undergo a deadweight survey to determine its actual light ship displacement and Longitudinal Center of Gravity (LCG). If the deadweight survey results are within 3 percent of the earlier vessel's approved light ship displacement and within 1 percent Length Between Perpendiculars (LBP) of the earlier vessel's approved light ship LCG, it may be accepted as a sister vessel and use the earlier vessel's approved light ship Vertical Center of Gravity (VCG); and

(7) If no vessel of the class previously underwent a stability test, then one vessel of the class must undergo a stability test in accordance with 46 CFR Part 170 Subpart F, and the sister vessel(s) must undergo a deadweight survey in accordance with paragraph (a)(6) of this section.

(b) A statement verifying sister status from an individual meeting the requirements of § 144.225 of this section must be retained and produced upon request.

§ 144.240 Marking of towing vessels.

(a) The hull of each documented towing vessel must be marked as required by part 67 of this chapter.

(b) The hull of each undocumented towing vessel must be marked with its name and hailing port.

(c) A towing vessel required to comply with §§ 144.315 and 144.415 must have the drafts of the vessel plainly and legibly marked up the stem and upon the sternpost or rudderpost or at any place at the stern of the vessel that is easily observed. The bottom of each mark must indicate the draft.

(d) Each towing vessel assigned a load line must have load line markings and deck line markings permanently scribed or embossed as required by subchapter E of this chapter.

(e) Watertight doors and watertight hatches must be marked on both sides in clearly legible letters at least 25 millimeters (1 inch) high: ''WATERTIGHT DOOR—KEEP CLOSED'' or ''WATERTIGHT HATCH—KEEP CLOSED''.

(f) All escape hatches and other emergency exits used as means of escape must be marked on both sides in clearly legible letters at least 50 millimeters (2 inches) high: ''EMERGENCY EXIT, KEEP CLEAR''.

Subpart C—Existing Towing Vessels

§ 144.300 Applicability.

This subpart applies to all existing towing vessels as defined in § 136.110 of this subchapter.

§ 144.305 General.

(a) Except as otherwise required in this part, an existing towing vessel must comply with the construction and arrangement standards that were applicable to the vessel prior to the implementation date of these regulations.

(b) Alterations or modifications made to the structure or arrangements of an existing towing vessel that are a major conversion, on or after the [effective date of regulations], must comply with the regulations of this part.

(c) Repairs conducted on an existing towing vessel, resulting in no significant changes to the original structure or arrangement of the vessel, must comply with the standards applicable to the vessel at the time of construction or as an alternative, with the regulations in this part.

§ 144.310 Structural standards.

(a) A existing towing vessel classed by the American Bureau of Shipping (ABS) in accordance with their rules as appropriate for the intended service and routes of the vessel, meets the structural standards of this subpart.

(b) A existing towing vessel with a valid load line certificate issued in accordance with Subchapter E of this chapter may be deemed in compliance with the structural requirements of this subpart.

(c) A existing towing vessel built to International Convention for Safety of Life at Sea (SOLAS) 1974, as amended, is considered to be in compliance with this part.

(d) A existing towing vessel built and equipped to conform to ABS rules appropriate for the intended service and routes, but not currently classed, may be deemed to be in compliance with this subpart, provided that the vessel continues to conform to ABS rules.

(e) The current standards of other recognized classification societies may be accepted upon approval by the Coast Guard.

(f) Classification by a recognized classification society is not required.

§ 144.315 Stability.

(a) This section applies to an existing towing vessel with a previously issued stability document.

(b) Each existing towing vessel operating under a previously issued stability document must continue to operate in accordance with the conditions specified therein and the requirements of this section.

(c)(1) A weight and moment history of changes to the vessel since approval of its light ship characteristics (displacement, Longitudinal Center of Gravity (LCG) and Vertical Center of Gravity (VCG)) shall be maintained. All weight modifications to the vessel (additions, removals, and relocations) shall be recorded in the history, along with a description of the change(s), when and where accomplished, moment arms, *etc.* After each modification, the light ship characteristics shall be recalculated.

(2) When the aggregate weight change (absolute total of all additions, removals, and relocations) is more than 2 percent of the vessel's approved light ship displacement, or the recalculated change in the vessel's light ship LCG is more than 1 percent of its length between perpendiculars (LBP), a deadweight survey shall be performed to determine the vessel's current light ship displacement and LCG. If the deadweight survey results are within 1 percent of the recalculated light ship displacement and within 1 percent LBP of the recalculated light ship LCG, then the recalculated light ship VCG can be accepted as accurate. If, however, the deadweight survey results are outside these tolerances, then the vessel must undergo a full stability test in accordance with 46 CFR 170 subpart F.

(3) When the aggregate weight change is more than 10 percent of the vessel's approved light ship displacement, the vessel must undergo a full stability test in accordance with 46 CFR Part 170 Subpart F.

(d) The cognizant Officer in Charge, Marine Inspection may restrict the route of an existing towing vessel based on concerns for the vessel's stability.

§ 144.320 Watertight integrity.

(a) An existing towing vessel must comply with the watertight integrity regulations which were applicable to the vessel on [EFFECTIVE DATE OF FINAL RULE], except that:

(1) Hatches, doors, vent closures, and other fittings affecting the watertight integrity of the vessel must be in place and operable;

(2) Decks and bulkheads designed to be watertight or weathertight must be maintained in that condition;

(3) Piping systems that penetrate the hull and tanks that are integral to the hull must be made of appropriate metal;

(4) Each existing towing vessel fitted with installed bulwarks around the exterior of the main deck must have sufficient freeing ports or scuppers or a

combination of freeing ports and scuppers to allow water to run off the deck quickly without adversely affecting the stability of the vessel; and

(5) Closure devices must be provided for cabin or hull penetrations, which open to the exterior of the vessel and which may allow water to enter the vessel. These devices must be suitable for the expected route.

(b) The cognizant Officer in Charge, Marine Inspection may require review of an existing towing vessel's watertight and weathertight integrity. This review may be performed by an individual meeting § 144.225 of this part. The review may include an examination of drawings or plans that show the original placement of decks and bulkheads.

§ 144.325 Visibility from pilothouse.

(a) Windows and other openings at the pilothouse of an existing towing vessel must be of sufficient size and properly located to provide a clear field of vision for safe operation in any condition.

(b) Means must be provided to ensure that windows immediately forward of the steering station in the pilothouse allow for adequate visibility to ensure safe navigation regardless of weather conditions. This may include mechanical means such as windshield wipers, defoggers, clear-view screens, or other such means, taking into consideration the intended route of the vessel.

§ 144.330 Emergency escape.

(a) Where practicable, each space on an existing towing vessel where crew may be quartered or normally employed must have at least two means of escape.

(b) The two required means of escape must be widely separated and, if possible, at opposite ends or sides of the space. Means may include normal and emergency exits, passageways, stairways, ladders, deck scuttles, doors, and windows.

(c) On an existing towing vessel of 65 feet (19.8 meters) or less in length, a window or windshield of sufficient size and proper accessibility may be used as one of the required means of escape from an enclosed space, provided it:

(1) Does not lead directly overboard;

(2) Is suitably marked; and

(3) Has a means to open a window or break a glass.

(d) Only one means of escape is required from a space where:

(1) The space has a deck area less than 30 square meters (322 square feet);

(2) There is no stove, heater, or other source of fire in the space;

(3) The means of escape is located as far as possible from a machinery space or fuel tank; and

(4) If an accommodation space, the single means of escape does not include a deck scuttle or a ladder.

(e) Existing arrangements may be retained if it is impracticable or unreasonable to provide two means of escape.

§ 144.335 Handrails and bulwarks.

(a) Rails or equivalent protection must be installed on existing towing vessels near the periphery of all decks accessible to crew. Equivalent protection may include lifelines, wire rope, chains, and bulwarks that provide strength and support equivalent to fixed rails.

(b) In areas where space limitations make deck rails impractical, such as at narrow catwalks in way of deckhouse sides, hand grabs may be substituted.

§ 144.340 Storm rails.

On existing towing vessels in ocean and coastwise service, suitable storm rails must be installed in all passageways and at the deckhouse sides where persons onboard might have normal access. Storm rails must be installed on both sides of passageways which are 6 feet or more in width.

§ 144.345 Guards in dangerous places.

An exposed hazard on existing towing vessels, such as gears and rotating machinery, must be protected by a cover guard or rail. This is not meant to restrict access to towing equipment such as winches, drums, towing gear or steering compartment equipment necessary for the operation of the vessel.

§ 144.350 Exhausts.

(a) Exhausts of internal-combustion engines, galley uptakes, and similar sources of ignition on existing towing vessels must be kept clear of and insulated from woodwork and other combustible matter.

(b) Each exhaust pipe from an internal combustion engine which is within reach of personnel must be insulated or otherwise guarded to prevent burns.

§ 144.355 Crew spaces.

(a) Overnight accommodations must be provided for crewmembers on an existing towing vessel if it is operated more than 12 hours in a 24-hour period, unless the crew is put ashore and the vessel is provided with a new crew.

(b) Crew accommodation spaces and work spaces must be of sufficient size, adequate construction, and with suitable equipment to provide for the safe operation of the vessel and the protection and accommodation of the crew in a manner practicable for the size, facilities, service, route, and modes of operation of the vessel.

(c) The deck above a crew accommodation space must be located above the deepest load waterline.

(d) Condition of the crew accommodations should consider the importance of crew rest. Factors to consider include: vibrations, ambient light, noise levels, and general comfort. Every effort should be made to ensure that quarters help provide a suitable environment for sleep and off-duty rest.

§ 144.360 Ventilation for accommodations.

(a) Each accommodation space on an existing towing vessel must be ventilated in a manner suitable for the purpose of the space.

(b) Existing towing vessels of more than 65 feet (19.8 meters) in length with overnight accommodations must have mechanical ventilation systems unless a natural system, such as opening windows, portholes, or doors, will provide adequate ventilation in ordinary weather.

(c) Means must be provided for stopping each fan in a ventilation system serving machinery spaces and for closing, in case of fire, each doorway, ventilator, and annular space around funnels and other openings into such spaces.

Subpart D—New Towing Vessels

§ 144.400 Applicability.

This subpart applies to new towing vessels as defined in § 136.110 this subchapter.

§ 144.405 Vessels built to class.

A new towing vessel classed by the American Bureau of Shipping in accordance with their rules as appropriate for the intended service and routes, meets the structural standards of this subpart.

§ 144.410 Structural standards.

(a) Except as provided by paragraphs (b) and (d) of this section, compliance with the construction and structural rules established by the American Bureau of Shipping is acceptable for the design and construction of a new towing vessel.

(1) For new towing vessels to be certificated for service on lakes, bays, and sounds, limited coastwise, coastwise, and oceans routes, American Bureau of Shipping (ABS) Rules for Building and Classing Steel Vessels Under 90 Meters (295 Feet) in Length (incorporated by reference in § 144.110 of this part) apply.

(2) For new towing vessels to be certificated for service on rivers or intracoastal waterways routes, ABS Rules for Building and Classing Steel Vessels for Service on Rivers and

Intracoastal Waterways (incorporated by reference in § 144.110 of this part) apply.

(b) The current standards of a recognized classification society, other than ABS may be used if they provide an equivalent level of safety.

(c) Classification by a recognized classification society is not required.

(d) Application may be made for use of alternative standards. Consideration of alternative standards will be given on a case-by-case basis upon review of vessel size, service, route, configuration, and other factors as deemed appropriate by the Commanding Officer, Marine Safety Center (MSC).

(e) The plans required by § 144.230 of this part must specify the standard to which the vessel is designed.

(f) The standard selected must be applied throughout the vessel including design, construction, installation, maintenance, alteration, and repair. Deviations are subject to approval by the Commanding Officer, MSC.

§ 144.415 Stability.

(a) Except as otherwise provided in paragraphs (b) and (c) of this section, each new towing vessel must meet the applicable stability requirements of part 170 and subpart E of part 173 of this chapter.

(b) For new towing vessels with a load line, the review, approval, and issuance of stability documentation (including stability tests) per §§ 170.110 and 170.120, and 170 subpart F must be done by the load line issuing authority. For new towing vessels without a load line, these functions must be done by an individual meeting the requirements of § 144.225 of this part.

(c)(1) Each new towing vessel certificated to operate on protected waters must meet the requirements of § 170.173(e)(2);

(2) Each new towing vessel certificated to operate on partially protected waters must meet the requirements of §§ 170.170 and 170.173(e)(1);

(3) Each new towing vessel certificated to operate on exposed waters or that requires a load line must meet the requirements of §§ 170.170 and 174.145.

(d) Each new towing vessel equipped for lifting must meet the requirements of subpart B of part 173 of this chapter.

(e)(1) A weight and moment history of changes to the vessel since approval of its light ship characteristics (displacement, Longitudinal Center of Gravity (LCG) and Vertical Center of Gravity (VCG)) shall be maintained. All weight modifications to the vessel (additions, removals, and relocations) shall be recorded in the history, along with a description of the change(s), when and where accomplished, moment arms, *etc.* After each modification, the light ship characteristics shall be recalculated.

(2) When the aggregate weight change (absolute total of all additions, removals, and relocations) is more than two percent of the vessel's approved light ship displacement, or the recalculated change in the vessel's light ship LCG is more than 1 percent of its length between perpendiculars (LBP), a deadweight survey shall be performed to determine the vessel's current light ship displacement and LCG. If the deadweight survey results are within 1 percent of the recalculated light ship displacement and within 1 percent LBP of the recalculated light ship LCG, then the recalculated light ship VCG can be accepted as accurate. If, however, the deadweight survey results are outside these tolerances, then the vessel must undergo a full stability test in accordance with 46 CFR 170 subpart F.

(3) When the aggregate weight change is more than 10 percent of the vessel's approved light ship displacement, the vessel must undergo a full stability test in accordance with 46 CFR part 170 subpart F.

(f) The cognizant Officer in Charge, Marine Inspection may restrict the route of a towing vessel based on concerns for the vessel's stability.

§ 144.420 Minimum standards.

Regardless of the construction and arrangements standards used, each new towing vessel must, as a minimum, meet the requirements of this subpart and subparts B and C of this part, as appropriate.

§ 144.425 Visibility.

(a) Each new towing vessel must be constructed in order to ensure a clear field of vision from the operating station. The field of vision must extend over an arc from dead ahead to at least 60 degrees on either side of the vessel.

(b) If towing astern, the primary steering station must be provided with a view aft.

(c) Means must be provided to ensure that windows immediately forward of the steering station in the pilothouse allow for adequate visibility to ensure safe navigation regardless of weather conditions. This may include mechanical means such as windshield wipers, defoggers, clear-view screens, or other such means, as appropriate for the intended route.

§ 144.430 Windows and portholes.

(a) Glass and other glazing materials used in windows of new towing vessels must be materials that will not break into dangerous fragments if fractured.

(b) Each window or porthole, and its means of attachment to the hull or the deckhouse, must be capable of withstanding the maximum expected load from wind and waves, due to its location on the vessel and the vessel's authorized route.

(c) Any covering or protection placed over a window or porthole that could be used as a means of escape must be able to be readily removed or opened from within the space.

§ 144.435 General fire protection.

(a) Each new towing vessel must be designed and constructed to minimize fire hazards as far as reasonable and practicable.

(b) Machinery and fuel tank spaces must be separated from accommodation spaces by bulkheads. Doors may be installed provided they are the self-closing type.

(c) Exhausts of internal-combustion engines, galley uptakes, and similar sources capable of starting a fire must be kept clear of and insulated from woodwork and other combustible matter.

(d) Paint lockers and similar compartments must be constructed of steel or be wholly lined with steel and comply with § 142.225 of this subchapter.

(e) Unless other means are provided to ensure that a potential waste receptacle fire would be limited to the receptacle, waste receptacles must be constructed of noncombustible materials with no openings in the sides or bottom.

(f) All mattresses must comply with either:

(1) The U.S. Department of Commerce Standard for Mattress Flammability (FF 4–72.16), 16 CFR part 1632, Subpart A and not contain polyurethane foam; or

(2) International Maritime Organization Resolution A.688(17) Fire Test Procedures For Ignitability of Bedding Components (incorporated by reference in § 144.110 of this part). Mattresses that are tested to this standard may contain polyurethane foam.

Dated: July 19, 2011.

Robert J. Papp, Jr.,

Admiral, U.S. Coast Guard, Commandant.

[FR Doc. 2011–18989 Filed 8–10–11; 8:45 am]

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Part IV

Department of the Interior

Fish and Wildlife Service

50 CFR Part 17

Endangered and Threatened Wildlife and Plants; Listing Six Foreign Birds as Endangered Throughout Their Range; Final Rule

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[FWS–R9–ES–2009–0084; MO 92210–1111F114 B6]

RIN 1018–AW39

Endangered and Threatened Wildlife and Plants; Listing Six Foreign Birds as Endangered Throughout Their Range

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Final rule.

SUMMARY: We, the U.S. Fish and Wildlife Service, determine endangered status for the following six foreign species found on islands in French Polynesia and in Europe, Southeast Asia, and Africa: Cantabrian capercaillie (*Tetrao urogallus cantabricus*); Marquesan imperial pigeon (*Ducula galeata*); the Eiao Marquesas reed-warbler (*Acrocephalus percernis aquilonis*), previously referred to as (*Acrocephalus mendanae aquilonis*); greater adjutant (*Leptoptilos dubius*); Jerdon's courser (*Rhinoptilus bitorquatus*); and slender-billed curlew (*Numenius tenuirostris*), under the Endangered Species Act of 1973 (Act), as amended. This final rule implements the Federal protections provided by the Act for these species.

DATES: This rule becomes effective September 12, 2011.

ADDRESSES: This final rule is available on the Internet at *http://www.regulations.gov* and comments and materials received, as well as supporting documentation used in the preparation of this rule, will be available for public inspection, by appointment, during normal business hours at: U.S. Fish and Wildlife Service, 4401 N. Fairfax Drive, Suite 400, Arlington, VA 22203.

FOR FURTHER INFORMATION CONTACT: Janine Van Norman, Chief, Branch of Foreign Species, Endangered Species Program, U.S. Fish and Wildlife Service, 4401 North Fairfax Drive, Room 420, Arlington, VA 22203; telephone 703–358–2171; facsimile 703–358–1735. If you use a telecommunications device for the deaf (TDD), call the Federal Information Relay Service (FIRS) at 800–877–8339.

SUPPLEMENTARY INFORMATION:

Background

The Endangered Species Act of 1973, as amended (Act) (16 U.S.C. 1531 *et seq.*) is a law that was passed to prevent extinction of species by providing measures to help alleviate the loss of species and their habitats. Before a plant or animal species can receive the protection provided by the Act, it must first be added to the Federal Lists of Threatened and Endangered Wildlife and Plants; section 4 of the Act and its implementing regulations at 50 CFR part 424 set forth the procedures for adding species to these lists.

Previous Federal Actions

On January 5, 2010, the Service published in the **Federal Register** a rule proposing to list these six foreign bird species as endangered under the Act (75 FR 286). Following publication of the proposed rule, we implemented the Service's peer review process and opened a 60-day comment period to solicit scientific and commercial information on the species from all interested parties. For more detailed information on previous Federal actions, please refer to the January 2010 proposed rule.

Summary of Comments and Recommendations

We base this finding on a review of the best scientific and commercial information available, including all information received during the public comment period. In the January 5, 2010, proposed rule, we requested that all interested parties submit information that might contribute to development of a final rule. We also contacted appropriate scientific experts and organizations and invited them to comment on the proposed listings. We received comments from 10 individuals; five of which were from peer reviewers.

We reviewed all comments we received from the public and peer reviewers for substantive issues and new information regarding the proposed listing of these species, and we address those comments below. Overall, the commenters and peer reviewers supported the proposed listing. Nine comments included additional information for consideration; the remaining comment simply supported the proposed listing without providing scientific or commercial data.

Peer Review

In accordance with our policy published on July 1, 1994 (59 FR 34270), we solicited expert opinions from 21 individuals with scientific expertise that included familiarity with the species, the geographic region in which the species occurs, and conservation biology principles. We received responses from five of the peer reviewers from whom we requested comments. They generally agreed that the description of the biology and habitat for the species was accurate and based on all relevant literature. Some new information was provided for some of the species, as well as technical clarifications, as described below. Technical corrections suggested by the peer reviewers have been incorporated into this final rule. In some cases, it has been indicated in the citations by ''personal communication'' (pers. comm.), which could indicate either an e-mail or telephone conversation; while in other cases, the research citation is provided.

Peer Reviewer Comments

(1) *Comment:* Two peer reviewers provided comments and additional literature regarding the Cantabrian capercaillie's diet, noting that the diet for the subspecies is unique compared to other capercaillie species.

Our Response: We reviewed the additional literature provided and updated the information on the subspecies' population estimate and diet, highlighting the use of different plants throughout the season.

(2) Comment: One peer reviewer stated that grouse, including capercaillie, do not have ''crests,'' but supraorbital combs and that the description of the bird given was not a good one. Another peer reviewer noted that the species description included only the male plumage and did not describe the female.

Our Response: The ''crests'' in the species description given in the proposed rule refers to a scarlet crest-shaped area above the eyes. We have replaced ''crests'' with ''supraorbital combs.'' We have also revised the species description to include more specific details of the species' traits and included a description of the female.

(3) Comment: One peer reviewer provided additional literature on differences in habitat selection within the Cantabrian capercaillie subspecies.

Our Response: We have reviewed the provided literature and have revised our discussion on the Cantabrian capercaillie habitat to reflect the slight differences in the preferred habitat of hens and cocks during the summer.

(4) Comment: One peer reviewer stated that there was not enough data available to support information on Cantabrian capercaillie population subdivision.

Our Response: The peer reviewer is referring to a study, conducted by Pollo *et al.* (2005), which we included in our discussion of the population decline in Cantabrian capercaillie. The study counted singing males in leks located across the southern slope of the

Cantabrian Mountains. The author considered a set of leks of a side-valley or a continuous forested habitat, generally separated by intervening ridges, to be a subpopulation. There is no information indicating that these groupings are true subpopulations. Based on this, we removed the language referring to subpopulations and reported the results of the study in total number of singing males across the southern slope.

(5) Comment: One peer reviewer stated there were updates on the phylogeography of the Cantabrian Capercaillie and its potential significance for future management, and provided additional literature.

Our Response: We reviewed the provided literature and incorporated the results of a genetic study under the Conservation Status section for this species.

(6) Comment: One peer reviewer provided clarification on the IUCN assessment process.

Our Response: Our discussion under the Conservation Status section of the proposed rule suggested that the International Union for Conservation of Nature (IUCN) had decided not to list the Cantabrian subspecies. All bird species are regularly assessed by the IUCN; however, subspecies are often omitted because of capacity limitations, although IUCN Red List categories and criteria can be applied to subspecies. We have revised the discussion per the peer reviewer's comment.

(7) Comment: One peer reviewer suggested that the common name Eiao Polynesian warbler was misleading and suggested a more specific English common name, Eiao Marquesas reed-warbler. This peer reviewer also provided additional citations for the Eiao Polynesian warbler and Marquesan imperial pigeon.

Our Response: The peer reviewer pointed out that species of the genus *Acrocephalus* are specifically reed-warblers and there are several species which inhabit the Polynesian region. We have changed our use of Eiao Polynesian warbler to Eiao Marquesas reed-warbler to more clearly refer to the reed-warbler that resides on Eiao Island in the Marquesas. We also reviewed the suggested citations and updated the information on clutch size for the Eiao Marquesas reed-warbler and population information for the Marquesan imperial pigeon.

(8) Comment: One peer reviewer provided additional citations regarding the description of the Jerdon's courser. This peer reviewer also provided information on hunting as a threat to the Jerdon't courser.

Our Response: We have reviewed the suggested citation and have corrected the species description for the Jerdon's courser. Also, we have added information on hunting as a potential threat to this species, but also note that there is no quantitative information on which to analyze this threat.

(9) Comment: One peer reviewer provided two additional citations for consideration regarding the slender-billed curlew.

Our Response: We reviewed the suggested citations and included additional information on nesting habitat and alterations to the nesting habitat described by Ushakov in 1924.

Public Comments

(10) Comment: One commenter suggested we also consider protecting the habitat of these six species.

Our Response: The Service does not have the authority to purchase or similarly protect habitat in areas under the jurisdiction of other countries. However, recognition through listing results in public awareness, and encourages and results in conservation actions by Federal and State governments, private agencies and groups, and individuals; these actions may address the conservation of habitat needed by foreign-listed species. The Act also authorizes the provision of limited financial assistance for the development and management of programs that the Secretary of the Interior determines to be necessary or useful for the conservation of endangered and threatened species in foreign countries; these programs may also be aimed at the conservation of habitat needed by listed species.

(11) Comment: One comment provided a technical correction to the status of the Cantabrian capercaillie under Spain's National Catalog of Endangered Species and provided the amendment changing its status to ''in danger of extinction.'' This commenter also provided additional literature regarding population estimates for the Cantabrian capercaillie and a recent decree approving a recovery plan for this subspecies.

Our Response: Under the Conservation Status section of the Cantabrian capercaillie, we have revised our text to indicate that this subspecies is listed as ''in danger of extinction'' based on the 2005 amendment changing its status from ''vulnerable.'' We also reviewed the information on population estimates along with the additional citations provided by two peer reviewers (discussed above under *Peer Reviewer Comments*). We have updated the information on the subspecies' population estimate. We added information under Factor D relating to the approved Recovery Plan and the protections and measures it provides.

(12) Comment: One commenter provided two citations and stated that the Cantabrian capercaillie habitat consists of Scots pine (*Pinus sylvestris*) and disappearance of pine trees in the Cantabrian Mountains threatens the Cantabrian capercaillie. The commenter further states that future habitat alteration due to climate change will likely further threaten and impact the species.

Our Response: After review of the two citations, we do not agree with the commenter's conclusions. It is our opinion that the first citation given by the commenter (Science Daily 2008, unpaginated) misinterprets the study and conclusions of Rubiales *et al.* (2008). To begin, the Cantabrian capercaillie occurs in entirely deciduous forests, not pine forests. In fact, this habitat difference is part of the basis for the Cantabrian capercaillie being described as a separate subspecies. Furthermore, the Rubiales *et al.* (2008) article describes the historical biogeography of Scots pine in the Cantabrian range and only briefly compares the trends in distribution of Scots pine and the capercaillie species as a whole, not just the Cantabrian capercaillie subspecies (Rubiales *et al.* 2008, pp. 6–7). The journal article does conclude that today's Scots pine and capercaillie populations are now highly fragmented and their future, given the predictions of global climate change, is uncertain (Rubiales *et al.* 2008, p. 1); however, this conclusion is referring to the species as a whole. Given that the other subspecies of capercaillie occur in entirely coniferous or mixed-coniferous forests, this statement is more appropriate to those subspecies and not to the Cantabrian capercaillie. We did not find, or receive, any information on climate change in the region of the Cantabrian capercaillie or information on the impact on deciduous forests in this area. Therefore, we did not add any information on the impact of climate change to the Cantabrian capercaillie.

(13) Comment: One commenter stated that the slender-billed curlew has been identified as a species threatened by climate change due to its small and declining population size and area of occupancy. The commenter also provided an additional citation to support this statement.

Our Response: We have reviewed the suggested literature and have included under Factor E additional information on climate change predictions within the African-Eurasian Waterbird Flyway and potential impacts to slender-billed curlew based on these predictions.

Summary of Changes From Proposed Rule

We fully considered comments from the public and peer reviewers on the proposed rule to develop this final listing of these six foreign bird species. This final rule incorporates changes to our proposed listing based on the comments that we received that are discussed above and newly available scientific and commercial information. Reviewers generally commented that the proposed rule was very thorough and comprehensive. We made some technical corrections based on new, although limited, information. None of the information, however, changed our determination that listing these species as endangered is warranted.

One substantive change we have made is in our analysis of the slender-billed curlew. In our proposed rule, we concluded that *Factor A.* (*Present or threatened destruction, modification, or curtailment of habitat or range*) was a threat to the species throughout its range. However, after further analysis of the information, we find that the loss of habitat is historic and that other species that use the same types of habitat have not experienced the same population decline seen in the slender-billed curlew. Furthermore, since it is not known what habitat the slender-billed curlew currently uses when in its nesting grounds, passage areas, or wintering grounds, we cannot properly assess the current or potential future threat of habitat modification or the impacts on this species. Therefore, we find that *Factor A* is not a threat to the species. This change did not alter our overall determination that the slender-billed curlew is in danger of extinction and should be listed as endangered under the Act.

Species Information and Factors Affecting the Species

Section 4 of the Act (16 U.S.C. 1533), and its implementing regulations at 50 CFR part 424, set forth the procedures for adding species to the Federal Lists of Endangered and Threatened Wildlife and Plants. Under section 4(a)(1) of the Act, we may list a species based on any of the following five factors: (A) The present or threatened destruction, modification, or curtailment of its habitat or range; (B) overutilization for commercial, recreational, scientific, or educational purposes; (C) disease or predation; (D) the inadequacy of existing regulatory mechanisms; and (E) other natural or manmade factors affecting its continued existence. Listing actions may be warranted based on any of the above threat factors, singly or in combination.

Despite the fact that global climate changes are occurring and affecting habitat, the climate change models that are currently available do not yet enable us to make meaningful predictions of climate change for specific, local areas (Parmesan and Matthews 2005, p. 354). We have obtained information on climate change for the slender-billed curlew and potential impacts to this species (See Factor E). However, we do not have models to predict how the climate in the range of the other Eurasian and Asian bird species will change, and we do not know how any change that may occur would affect these species. Nor do we have information on past and future weather patterns within the specific range of these species. Therefore, based on the current lack of information, we did not evaluate climate change as a threat to five of these species.

Below is a species-by-species description and analysis of the five factors. The species are considered in alphabetical order, beginning with the Cantabrian capercaillie, followed by the Eiao Marquesas reed-warbler, greater adjutant, Jerdon's courser, Marquesan Imperial Pigeon, and the slender-billed curlew.

I. Cantabrian capercaillie (*Tetrao urogallus cantabricus*)

Species Description

The Cantabrian capercaillie (*Tetrao urogallus cantabricus*) is a subspecies of the western capercaillie (*T. urogallus)* in the family Tetraonidae. The species in general is a large, very dark grouse of 80 to 115 centimeters (cm) in length (31 to 45 inches (in)), with the female being much smaller than the male. The species is characterized by having slate gray plumage with fine blackish vermiculation (wavelike pattern) around the head and neck. The breast is a glossy greenish-black. The wings are dark brown with a prominent white carpal patch and variable amount of white on the upper- and undertail-coverts (feathers) and the underparts. This bird has a long, rounded tail, an ivory white bill, and a scarlet supraorbital comb (above the eye). Females are mottled black, gray and buff with a large rusty patch on the breast (World Association of Zoos and Aquaria 2009, unpaginated). Based on ecological differences from other capercaillie subspecies (the Cantabrian capercaillie is the only subspecies that inhabits pure deciduous forests) and morphological differences from the Pyrenean capercaillie (*T. u. aquitanicus*) (Cantabrian capercaillie are lighter in color and have a smaller beak), the Cantabrian population was described as belonging to a different subspecies by Castroviejo 1976 (Rodríguez-Muñoz *et al.* 2007, pp. 660, 666).

The Cantabrian capercaillie once existed along the whole of the Cantabrian Mountain range from northern Portugal through Galicia, Asturias, and Leon, to Santander in northern Spain (IUCN Redbook 1979, p. 1). Currently its range is restricted to both the northern slope (Asturias and Cantabria provinces) and the southern slope (León and Palencia provinces) of the Cantabrian Mountains in northwest Spain. The subspecies inhabits an area of 1,700 square kilometers (km^2) (656 square miles (mi^2)), and its range is separated from its nearest neighboring subspecies of capercaillie (*T. u. aquitanus*) in the Pyrenees mountains by a distance of more than 300 km (186 mi) (Quevedo *et al.* 2006b, p. 268).

Unlike other capercaillie subspecies, the Cantabrian capercaillie occurs in entirely deciduous forests consisting of a rugged montane landscape of mature beech (*Fagus sylvatica*), sessile oak (*Quercus petraea*), and birch (*Betula pubescens*) (Rodríguez-Muñoz *et al.* 2007, pp. 659, 660; Banuelos *et al.* 2008, pp. 245–246) at elevations ranging from 800 to 1,800 m (2,600 to 5,900 ft). The Cantabrian capercaillie also uses other microhabitat types (broom (*Genista* spp.), meadow, and heath (*Erica* spp.)) selectively throughout the year (Quevedo *et al.* 2006b, p. 271). A recent study has found that some habitat partitioning occurs amongst the Cantabrian capercaillie. During the summer, hens and cocks are more associated with open areas than the forested spring display areas. Specifically, hens with broods are more associated with treeline birch forests, which are the most suitable areas for the species, and are characterized by a rich understory of shrubs such as heath and bilberry (*Vaccinium myrtillus*); hens without broods prefer a more rugged terrain; and cocks prefer beech or oak forests (Banuelos *et al.* 2008, p. 249).

Diet appears to be a driver of habitat selection (Blanco-Fontao *et al.* 2009, pp. 1, 6). In summer and autumn, the majority of the Cantabrian capercaillie diet consists of bilberry (mainly berries) and fern fronds. In winter, holly leaves (*Ilex aquifolium*), beech buds, bilberry shoots and fern fronds make up a majority of the diet, whereas only beech buds, bilberry shoots and fern fronds dominate the spring diet. Birch, oak, rowan (*Sorbus aucuparia*), heath, and broom are also consumed, but in much smaller amounts (Blanco-Fontao *et al.* 2009, p. 4).

The current population is likely less than 1,000 birds; however, reliable estimates are lacking (Storch 2007, p. 49). Population estimates for species of grouse are commonly assessed by counting males that gather during the breeding season to sing and display at leks (traditional places where males assemble during the mating season and engage in competitive displays to attract females). In a 1981–1982 survey of the southern slope, Pollo *et al.* (2005, p. 401) estimated a minimum number of 274 singing male capercaillie; in subsequent surveys from 1987–1989, 1998, and 2000–2003, only 219, 94, and 81 males were recorded, respectively, indicating a 70 percent reduction. This is equivalent to an average decline of 3 percent per year, or 22 percent over 8 years (Storch *et al.* 2006, p. 654). A study conducted from 2005 to 2007 found that only 30 percent of all known leks were occupied in the northern watershed of the species' range, indicating an occupancy decline of 5.4 percent. In the southern watershed, only 34.5 percent of all known leks in the area remain occupied (Bañuelos and Quevedo 2008, p. 5).

The area occupied by Cantabrian capercaillie in 1981–1982 covered up to approximately 2,070 km^2 (799 mi^2) of the southern slope (972 km^2 (375 mi^2) in the west and 1,098 km^2 (424 mi^2) in the east). Between 2000 and 2003, the area of occupancy had declined to 693 km^2 (268 mi^2), specifically 413 km^2 (159 mi^2) in the west and 280 km^2 (108 mi^2) in the east. Thus, over a 22-year period, there was a 66-percent reduction in the areas occupied by this subspecies on the southern slope of the Cantabrian Mountains (Pollo *et al.* 2005, p. 401). Based on this data, the subpopulation in the eastern portion of the range appears to be declining at a faster rate than the subpopulation in the western portion of the range.

Conservation Status

Although Storch *et al.* (2006 p. 653) noted that the Cantabrian capercaillie meets the criteria to be listed as ''Endangered'' on the IUCN Redlist due to ''rapid population declines, small population size, and severely fragmented range,'' it is currently not classified as such by the IUCN. The species (western capercaillie (*Tetrao urogallus*)) has been evaluated and is listed as Least Concern (Birdlife International 2009, unpaginated); subspecies are generally omitted due to capacity limitations, although the IUCN categories and criteria can be applied to subspecies (Storch *et al.* 2006 p. 653). The species is classified as ''in danger of extinction'' in Spain under the National Catalog of Endangered Species (Ministry of the Environment MAM Order/2231/2005). The species has not been formally considered for listing in the Convention on International Trade in Endangered Species of Wild Fauna and Flora (CITES) Appendices (*http://www.cites.org*). Recent phylogenetic studies indicate that the Cantabrian capercaillie forms a different clade from those of other European capercaillie, and factoring in ecological differences, qualifies as an Evolutionarily Significant Unit (Storch *et al.* 2006, p. 653; Rodríguez-Muñoz *et al.* 2007, p. 668). Combined with recent population trends and changes in distribution, Rodríguez-Muñoz *et al.* (2007, p. 668) suggest the status of this species should be defined as critical.

Summary of Factors Affecting the Cantabrian Capercaillie

A. Present or Threatened Destruction, Modification, or Curtailment of Habitat or Range

Numerous limiting factors influence the population dynamics of the Cantabrian capercaillie throughout its range, including habitat degradation, loss, and fragmentation (Storch 2000, p. 83; 2007, p. 96). Forest structure plays an important role in determining habitat suitability and occupancy. Quevedo *et al.* (2006b, p. 274) found that open forest structure with well-distributed bilberry shrubs were the preferred habitat type of Cantabrian capercaillie. Management of forest resources for timber production has caused and continues to cause significant changes in forest structure such as: Species composition, density and height of trees, forest patch size, and understory vegetation (Pollo *et al.* 2005, p. 406).

The historic range occupied by this subspecies (3,500 km^2 (1,350 mi^2)) has declined by more than 50 percent (Quevedo *et al.* 2006b, p. 268). The current range is severely fragmented, with low forest habitat cover (22 percent of the landscape) and most of the suitable habitat remaining in small patches less than 10 hectares (ha) (25 acres (ac)) in size (Garcia *et al.* 2005, p. 34). Patches of good-quality habitat are scarce and discontinuous, particularly in the central parts of the range (Quevedo *et al.* 2006b, p. 269), and leks in the smaller forest patches have been abandoned during the last few decades. The leks that remain occupied are now located farther from forest edges than those occupied in the 1980s (Quevedo *et al.* 2006b, p. 271).

Based on population surveys, forest fragments containing occupied leks in 2000 were significantly larger than fragments containing leks in the 1980s that have since been abandoned (Quevedo *et al.* 2006b, p. 271). The forest fragments from which the Cantabrian capercaillie has disappeared since the 1980s are small in size, and are the most isolated from other forest patches. In addition, the Cantabrian capercaillie have disappeared from forest patches located closest to the edge of the range in both the eastern and western subpopulations of the south slope of the Cantabrian Mountains, suggesting that forest fragmentation is playing an important role in the population dynamics of this subspecies (Quevedo *et al.* 2006b, p. 271). Research conducted on other subspecies of capercaillie indicate that the size of forest patches is correlated to the number of males that gather in leks to display, and that below a certain forest patch size, leks are abandoned (Quevedo *et al.* 2006b, p. 273).

In highly fragmented landscapes, forest patches are embedded in a matrix of other habitats, and forest dwellers like capercaillies frequently encounter open areas within their home range. Quevedo *et al.* (2006a, p. 197) developed a habitat suitability model for the Cantabrian capercaillie that assessed the relationship between forest patch size and occupancy. He determined that the subspecies still remains in habitat units that show habitat suitability indices below the cut-off values of the two best predictive models (decline and general), which may indicate a high risk of local extinction. Other researchers suggested that, should further habitat or connectivity loss occur, the Cantabrian capercaillie population may become so disaggregated that the few isolated subpopulations will be too small to ensure their own long-term persistence (Grimm and Storch 2000, p. 224).

A demographic model based on Bavarian alpine populations of capercaillie suggests a minimum viable population size of the order of 500 birds (Grimm and Storch 2000, p. 222). However, genetic data show clear signs of reduced variability in populations with numbers of individuals in the range of fewer than 1,000 birds, which indicates that a demographic minimum population of 500 birds may be too small to maintain high genetic variability (Segelbacher *et al.* 2003, p. 1779). Genetic consequences of habitat fragmentation exist for this species in the form of increased genetic differentiation due to increased isolation of populations (Segelbacher *et al.* 2003, p. 1779). Therefore, anthropogenic habitat deterioration and fragmentation not only leads to range contractions and extinctions, but may also have significant genetic, and thus, evolutionary consequences for the surviving populations (Segelbacher *et al.* 2003, p. 1779).

In summary, recent population surveys show this subspecies is continuing to decline throughout its current range, and subpopulations may be isolated from one another due to range contractions in the eastern and western portions of its range, leaving the central portion of the subspecies range abandoned (Pollo *et al.* 2005, p. 401). Some remaining populations may already have a high risk of local extinction (Quevedo *et al.* 2006a, p. 197). Management of forest resources for timber production continues to negatively affect forest structure, thereby affecting the quality, quantity, and distribution of suitable habitat available for this subspecies. In addition, the structure of the matrix of habitats located between forest patches is likely affecting the ability of capercaillies to disperse between subpopulations. Therefore, we find that present or threatened destruction, modification, or curtailment of the habitat or range is a threat to the continued existence of the Cantabrian capercaillie throughout its range.

B. Overutilization for Commercial, Recreational, Scientific, or Educational Purposes

Currently hunting of the Cantabrian capercaillie is illegal in Spain; however, illegal hunting still occurs (Storch 2000, p. 83; 2007, p. 96). Because this species congregates in leks, individuals are particularly easy targets, and poaching of protected grouse is considered common (Storch 2000, p. 15). It is unknown what the incidence of poaching is or what impact it is having on this subspecies; however, given the limited number of birds remaining and the reduced genetic variability already evident at current population levels, the further loss of breeding adults could have substantial impact on the subspecies. Therefore, we find that overutilization for recreational purposes is a threat to the continued existence of the Cantabrian capercaillie throughout its range.

C. Disease or Predation

Diseases and parasites have been proposed as factors associated with the decline of populations of other species within the same family of birds as the capercaillie (Tetraonidae) (Obeso *et al.* 2000, p. 191). In an attempt to determine if parasites were contributing to the decline of the Cantabrian capercaillie, researchers collected and analyzed fecal samples in 1998 from various localities across the range of this subspecies. The prevalence of common parasites (*Eimeria* sp. and *Capillaria* sp.) was present in 58 percent and 25 percent of the samples collected, respectively. However, both the intensity and average intensity of these parasites were very low compared to other populations of species of birds in the Tetraonidae family. Other parasites were found infrequently. The researchers concluded that it was unlikely that intestinal parasites were causing the decline of the Cantabrian capercaillie.

Based on the information above, we do not believe that parasite infestations are a significant factor in the decline of this subspecies. We are not aware of any species-specific information currently available that indicates that predation poses a threat to the species. Therefore, we are not considering disease or predation to be contributing threats to the continued existence of the Cantabrian capercaillie throughout its range.

D. Inadequacy of Existing Regulatory Mechanisms

This subspecies is currently classified as ''in danger of extinction'' in Spain under the National Catalog of Endangered Species, which affords it special protection (*e.g.,* additional regulation of activities in the forests of its range, regulation of trails and roads in the area, elimination of poaching, and protection of areas important to young). Although it is classified as ''in danger of extinction,'' as mentioned above (see Factor B), illegal hunting still occurs.

In conjunction with this subspecies being listed as ''in danger of extinction'' under the National Catalog of Endangered Species, a recovery plan for the Cantabrian capercaillie was approved by the Autonomous Community of Castilla and Leon. This official document approves the recovery plan and adopts measures for the protection of the species in the Community of Castilla and Leon (Decree 4/2009, dated January 15, 2009; Pollo 2010, pers. comm.). The purpose of the Recovery Plan is to foster necessary actions to allow the species to achieve a more favorable conservation status and to ensure its long-term viability and stop population decline. The Recovery Plan includes requirements that the effects to the Cantabrian capercaillie or its habitat be considered before a plan or activity can be implemented; restricting access to critical areas; suspension of resource exploitation activities following wildlife catastrophic events (*e.g.,* animal epidemics, poisoning, widespread wildfires) to allow for recovery; prohibiting certain activities within critical areas; and specific measures to meet the goals of the Recovery Plan.

The European Union (EU) Habitat Directive 92/43/EEC addresses the protection of habitat and species listed as endangered at the European scale (European Union 2008). Several habitat types valuable to capercaillie have been included in this Directive, such as in Appendix I, Section 9, Forests. The EU Bird Directive (79/407/EEC) lists the capercaillie in Annex I as a ''species that shall be subject to special habitat conservation measures in order to ensure their survival.'' Under this Directive, a network of Special Protected Areas (SPAs) comprising suitable habitat for Annex I species is to be designated. This network of SPAs and other protected sites are collectively referred to as Natura 2000. Several countries in Europe, including Spain, are in the process of establishing the network of SPAs. The remaining Cantabrian capercaillie populations occur primarily in recently established Natural Reserves in Spain that are part of the Natura 2000 network (Muniellos Biosphere Reserve). Management of natural resources by local communities is still allowed in areas designated as an SPA; however, the development of management plans to meet the various objectives of the Reserve network is required.

This subspecies is also afforded special protection under the Bern Convention (Convention on the Conservation of European Wildlife and Natural Habitats; European Treaty Series/104; Council of Europe 1979). The Cantabrian capercaillie is listed as ''strictly protected'' under Appendix II, which requires member states to ensure the conservation of the listed taxa and their habitats. Under this Convention, protections of Appendix-II species include the prohibition of: The deliberate capture, keeping, and killing of the species; deliberate damage or destruction of breeding sites; deliberate disturbance during the breeding season; deliberate taking or destruction of eggs; and the possession or trade of any individual of the species. We were unable to find information on the effectiveness of this designation in preventing further loss of Cantabrian capercaillie or its habitat; however, poaching of protected grouse is known to be common, suggesting that this designation has not been effectively implemented.

In November 2003, Spain enacted the ''Forest Law,'' which addresses the preservation and improvement of the forest and rangelands in Spain. This law requires development of plans for the management of forest resources, which are to include plans for fighting forest fires, establishment of danger zones based on fire risk, formulation of a defense plan in each established danger zone, the mandatory restoration of burned area, and the prohibition of changing forest use of a burned area into other uses for a period of 30 years. In addition, this law provides economic incentives for sustainable forest management by private landowners and local entities. We do not have information on the effectiveness of this law with regard to its ability to prevent negative impacts to Cantabrian capercaillie habitat.

Despite recent advances in protection of this subspecies and its habitat through EU Directives and protection under Spanish law and regulation, populations continue to decline (Bañuelos and Quevedo 2008, p. 5; Storch *et al.* 2006, p. 654; Pollo *et al.* 2005, p. 401), habitat continues to be degraded, lost, and fragmented (Storch 2000, p. 83; 2007, p. 96), and illegal poaching still occurs (Storch 2000, p. 83; 2007, p. 96). We were unable to find information on the effectiveness of any of these measures at reducing threats to the species. Therefore, we find that existing regulatory mechanisms are inadequate to ameliorate the current threats to the Cantabrian capercaillie throughout its range.

E. Other Natural or Manmade Factors Affecting the Species' Continued Existence

Suarez-Seoane and Roves (2004, pp. 395, 401) assessed the potential impacts of human disturbances in core populations of Cantabrian capercaillie in Natural Reserves in Spain. They found that locations selected as leks were located at the core of larger patches of forest and were less subject to human disturbance. They also found that Cantabrian capercaillie disappeared from leks situated in rolling hills at lower altitudes closer to houses, hunting sites, and repeatedly burned areas.

Recurring fires have also been implicated as a factor in the decline of the subspecies. An average of 85,652 ha (211,650 ac) of forested area per year over a 10-year period (1995–2005) has been consumed by fire in Spain (Lloyd 2007a, p. 1). On average, 80 percent of all fires in Spain are set intentionally by humans (Lloyd 2007a, p. 1). Suarez-Seoane and Garcia-Roves (2004, p. 405) found that the stability of Cantabrian capercaillie breeding areas throughout a 20-year period was mainly related to low fire recurrence in the surrounding area and few houses nearby. In addition, the species avoids areas that are recurrently burned because the areas lose their ability to regenerate and cannot produce the habitat the species requires (Suarez-Seoane and Garcia-Roves 2004, p. 406). We were unable to find information as to how many hectares of suitable Cantabrian capercaillie habitat is consumed by fire each year. However, since the species requires a low recurrence of fire, and both disturbance and fire frequency are likely to increase with human presence, this could be a potential threat to both habitat and individual birds where there is a high prevalence of disturbance and fire frequency.

In summary, disturbance from humans appears to impact the species; birds are typically found in areas of less anthropogenic disturbance and further from homes. Natural Protected Areas in Spain have seen an increase in human use for recreation and hunting. As human population centers expand and move closer to occupied habitat areas, increased disturbance to important breeding, feeding, and sheltering behaviors of this species is expected to occur. Additionally, as human presence increases, it is likely that both fires and disturbances will increase. Either or both of these factors have the potential to impact both individuals and their habitat. Therefore, we conclude that other natural or manmade factors, in the form of forest fires and disturbance, are threats to the continued existence of the Cantabrian capercaillie throughout its range.

Status Determination for the Cantabrian Capercaillie

We have carefully assessed the best available scientific and commercial information regarding the past, present, and potential future threats faced by the Cantabrian capercaillie. The species is currently at risk throughout all of its range due to ongoing threats of habitat destruction and modification (Factor A), overutilization (Factor B), inadequacy of existing regulatory mechanisms (Factor D), and other natural or manmade factors affecting its continued existence in the form of forest fires and disturbance (Factor E).

Section 3 of the Act defines an ''endangered species'' as ''any species which is in danger of extinction throughout all or a significant portion of its range'' and a ''threatened species'' as ''any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.''

The Cantabrian capercaillie is the most threatened subspecies of capercaillie; the current population is likely less than 1,000 individuals and continues to decline. Management of forest resources for timber production continues to negatively affect forest structure and the quality, quantity, and distribution of suitable habitat and the structure of the matrix between forest patches, which may be affecting the ability of capercaillie to disperse. In addition, hunting of Cantabrian capercaillie, although illegal, still occurs. Congregation at leks makes this species an easy target and particularly vulnerable as poaching of protected grouse is considered common. The level of poaching is unknown, but given the small population size and the already evident reduced genetic variability, further loss of breeding individuals could have a significant impact on the population. Regulatory mechanisms are in place to protect the subspecies and its habitat, but are inadequate to ameliorate current threats. Furthermore, as human population centers expand, increased disturbance to important breeding, feeding, and sheltering behaviors is expected, further affecting this subspecies. These threats are affecting the quality and quantity of suitable habitat, the ability of the species to disperse and expand their current range, and may affect the breeding capability of the populations. Without regulatory mechanisms to reduce or ameliorate these threats, negative impacts to the subspecies will continue. In considering these ongoing threats in combination with the currently small and declining Cantabrian capercaillie population, we determine that the magnitude of these threats are such that this subspecies is in danger of extinction throughout all of its range. Therefore, on the basis of the best available scientific and commercial information, we are listing the Cantabrian capercaillie as an endangered species throughout all of its range. Because we find that the Cantabrian capercaillie is endangered throughout all of its range, there is no reason to consider its status in a significant portion of its range.

II. Eiao Marquesas Reed-Warbler (*Acrocephalus percernis aquilonis*), Previously Referred to as Eiao Polynesian Warbler (*Acrocephalus mendanae aquilonis* and *Acrocephalus caffer aquilonis*)

Species Description

Due to the similarity of all the reed-warblers of Polynesia, these warblers were once considered a single, widespread species known as the long-billed reed-warbler (*Acrocephalus caffer*). The 1980 petition from Dr. Warren B. King included the Eiao Polynesian warbler (*Acrocephalus caffer aquilonis*), a subspecies of reed-warbler. The subspecies *aquilonis* denoted those warblers found on Eiao Island. The species was later split into three separate species: those of the Society Islands (*Acrocephalus caffer*), Tuamotu (*A. atyphus*), and Marquesas (*A. mendanae*) (Cibois *et al.* 2007, p. 1151). This subspecies then became known as *A. mendanae aquilonis.* Recent genetic research on Marquesas reed-warblers found two independent lineages: warblers found in the northern islands of the Marquesas Archipelago (Nuku Hiva, Eiao, Hatuta'a, and Ua Huka) and those found on the southern islands (Hiva Oa, Tahuata, Ua Pou, and Fatu Iva). As a result, the Marquesas species was split into two separate species; those of the four most northern islands (*A. percernis*) and those in the southern islands (*A. mendanae*). The reed-warblers found on Eiao are now classified as a subspecies of Northern Marquesas reed-warblers (*A. percernis aquilonis*) (Cibois *et al.* 2007, pp. 1155, 1160), with a suggested common name of Eiao Marquesas reed-warbler (Cibois 2010, pers. comm.).

The Eiao Marquesas reed-warbler (Eiao reed-warbler) is a large, insectivorous reed-warbler of the family Acrocephalidae. It is characterized by brown plumage with bright yellow underparts (Cibois *et al.* 2007, p. 1151). The Eiao reed-warbler is endemic to the island of Eiao in the French Polynesian Marquesas Archipelago in the Pacific Ocean. The Marquesas Archipelago is a territory of France located approximately 1,600 km (994 mi) northeast of Tahiti. Eiao Island is one of the northernmost islands in the Archipelago and encompasses 40 km^2 (15 mi^2).

Population densities of the Eiao reed-warbler are thought to be high within the remaining suitable habitat; one singing bird was found nearly every 40–50 m (131–164 ft). The total population is estimated at more than 2,000 birds (Raust 2007, pers. comm.). This population estimate is much larger than the 100–200 individuals last reported in 1987 by Thibault (as reported in FR 72 20184). It is unknown if the population actually increased from 1987 to 2007, or if the differences in the population estimates are a result of using different survey methodologies. We have no reliable information on the population trend of this subspecies.

Reed-warblers of the Polynesian islands utilize various habitats, ranging from shrubby vegetation in dry, lowland areas to humid forest in wet montane areas (Cibois *et al.* 2007, pp. 1151, 1153). Reed-warblers in general display strong territorial behavior (Cibois *et al.* 2007, p. 1152). Like other reed-warblers, the female Marquesas reed-warblers build the nest with little help from the male; the male incubates and broods three to four times a day, but never for more than 20 minutes at a time (Bruner 1974, p. 93). Vines, coconut fiber, and grasses are the most common nesting material (Mosher and Fancy 2002, p. 8). Warbler nests are found in the tops of trees and on vertical branches (Thibault *et al.* 2002, pp. 166, 169). Bruner (1974, p. 93) found the eggs of *A. mendanae* vary in base color, even within a nest, but are all blotched and speckled with white, brown, and black and clutch sizes range from two to five eggs. Incubation lasts 9 days and the young leave the nest and follow their parents after 10 days (Bruner 1974, p. 94).

Conservation Status

Marquesas reed-warblers (*A. mendanae*) are classified as ''of least concern'' by the IUCN (IUCN 2009a, unpaginated). However, it appears that the recent split of the Marquesas reed-warblers into the Northern and Southern Marquesas reed-warblers is not yet reflected in the IUCN assessment. Northern Marquesas reed-warblers (*A. percernis*) are protected under Law Number 95–257 in French Polynesia. The species has not been formally considered for listing in the CITES Appendices (*http://www.cites.org*).

Summary of Factors Affecting the Species

A. Present or Threatened Destruction, Modification, or Curtailment of Habitat or Range

Eiao Island was declared a Nature Reserve in 1971 and is not currently inhabited by humans. However, the entire island has been heavily impacted by introduced domestic livestock that have become feral (Manu 2009, unpaginated). Feral sheep have been identified as the main threat to the forest on the island (Thibault *et al.* 2002, p. 167). Sheep and pigs have devastated much of the vegetation and soil on Eiao, and native plant species have been largely replaced by introduced species (Merlin and Juvik 1992, pp. 604–606). Sheep have overgrazed the island, leaving areas completely denuded of vegetation. The exposed soil erodes from rainfall, further preventing native plants from regenerating (WWF 2001, unpaginated). Currently, only 10–20 percent of the island contains suitable habitat for the Eiao reed-warbler (Raust 2007, pers. comm.). These areas of suitable habitat are likely restricted to small refugia inaccessible to the feral livestock. We are not aware of any current efforts or future plans to reduce the number of feral domestic livestock on the island.

In summary, the ongoing habitat degradation from overgrazing livestock continues to have significant and ongoing impacts to the natural habitat for this subspecies. The current level of grazing on the island prevents recovery of native vegetation. Without active management of the feral livestock population on the island, the population of Eiao reed-warblers will continue to be restricted to small portions of the island that are inaccessible to the feral livestock. Furthermore, although the current estimated population is 2,000 individuals, the subspecies will not be able to expand to the rest of the island and recover beyond this current population level due to habitat loss. Because the Eiao reed-warbler is limited to one small island, the continuing loss of habitat makes this subspecies extremely vulnerable to extinction. Therefore, we find that present or threatened destruction, modification, or curtailment of the habitat or range are threats to the continued existence of the Eiao reed-warbler throughout its range.

B. Overutilization for Commercial, Recreational, Scientific, or Educational Purposes

We are unaware of any information currently available that indicates the use of this subspecies for any commercial, recreational, scientific, or educational purpose. As a result, we are not considering overutilization for commercial, recreational, scientific, or educational purposes to be a contributing factor to the continued existence of the Eiao reed-warbler throughout its range.

C. Disease or Predation

Avian diseases are a concern for species with restricted ranges and small populations, especially if the species is restricted to an island. Hawaii's avian malaria is a limiting factor for many species of native passerines and is dominant on other remote oceanic islands, including French Polynesia (Beadell *et al.* 2006, p. 2935). This strain was found in 9 out of 11 Marquesas reed-warblers collected on Nuku Hiva in 1987. However, because these birds were thought to be more robust (all Marquesas reed-warblers were considered *A. mendanae*), avian malaria was not thought to pose a threat to the species (Beadell *et al.* 2006, p. 2940). We have no data on whether Hawaii's avian malaria is present on Eiao or what effects it may have on the population of reed-warblers.

Black rats (*Rattus rattus*) were introduced to Eiao, Nuku Hiva, Ua Pou, Hiva Oa, Tahuata, and Fatu Iva of the Marquesas Archipelago in the early 20th century (Cibois *et al.* 2007, p. 1159); although Thibault *et al.* (2002, p. 169) state that the presence of black rats on Eiao is only suspected. A connection between the presence of rats and the decline and extirpation of birds has been well documented (Blanvillain *et al.* 2002, p. 146; Thibault *et al.* 2002, p. 162; Meyer and Butaud 2009, pp. 1169–1170). Specifically, predation on eggs, nestlings, or adults by rats has been implicated as an important factor in the extinction of Pacific island birds (Thibault *et al.* 2002, p. 162). However, Thibault *et al.* (2002, pp. 165, 169) did not find a significant effect of rats on the abundance of Polynesian warblers. It is thought that the position of warbler nests on vertical branches close to the tops of trees makes them less accessible to rats (Thibault *et al.* 2002, p. 169), even though rats are known to be good climbers.

The common myna (*Acridotheres tristis*), an introduced bird species, may contribute to the spread of invasive plant species by consuming their fruit and may also prey on the eggs and nestlings of native birds species or outcompete native bird species for nesting sites. The myna is thought to have contributed to the decline of another reed-warbler endemic to the Marquesas (*A. caffer mendanae*) (Global Invasive Species Database 2009, unpaginated). Mynas do not currently occur on Eiao Island. Furthermore, Thibault *et al.* (2002, p. 165) found no significant effect of mynas on Polynesian warblers in Marquesas. If the myna expands its range and colonizes Eiao Island, it is unknown to what extent predation would affect the Eiao reed-warbler.

In summary, although the presence of avian malaria has been documented on Eiao and the presence of introduced rats is suspected, there is no data indicating that either is affecting the warbler population on Eiao. Nest location appears to be high enough in the trees to avoid significant predation from the introduced rat. Mynas are not known to inhabit Eiao Island, and it is not clear that they would negatively impact the warbler population if they were to colonize Eiao. Therefore, we find that disease and predation are not a threat to the continued existence of the Eiao reed-warbler throughout its range.

D. Inadequacy of Existing Regulatory Mechanisms

The Eiao reed-warbler is a protected species in French Polynesia. Northern Marquesas reed-warblers (*A. percernis*) are classified as a Category A species under Law Number 95–257. Article 16 of this law prohibits the collection and exportation of species listed under Category A. In addition, under Part 23 of Law 95–257, the introduced myna bird species, which is commonly known to outcompete other bird species, is considered a danger to the local avifauna and is listed as ''threatening biodiversity.'' Part 23 also prohibits importation of all new specimens of species listed as ''threatening biodiversity,'' and translocation from one island to another is prohibited. As described above, Eiao Island is not currently inhabited by humans and we found that overutilization for commercial, recreational, scientific, or educational purposes is not a threat to this subspecies. Furthermore, mynas do not occur on Eiao Island and is not a threat to the Eiao reed-warbler. Although this law may provide adequate protection to this subspecies from these threats, it does not protect the Eiao reed-warbler from current threats such as habitat destruction.

The French Environmental Code, Article L411–1, prohibits the destruction or poaching of eggs or nests; mutilation, destruction, capture or poaching, intentional disturbance, the practice of taxidermy, transport, peddling, use, possession, offer for sale, and the sale or the purchase of non-domesticated species in need of conservation, including northern Marquesas reed-warblers (*A. percernis*). It also prohibits the destruction, alteration, or degradation of habitat for these species. As overutilization for commercial, recreational, scientific, or educational purposes is not a threat to this subspecies, this regulation may provide adequate protection against this threat; however, habitat destruction by overgrazing livestock remains a problem on Eiao Island. Therefore this regulation does not provide adequate protection against threats currently faced by this subspecies.

Hunting and destruction of all species of birds in French Polynesia were prohibited by a 1967 decree (Villard *et al.* 2003, p. 193); however, destruction of birds which have been listed as ''threatening biodiversity'' is legal. Furthermore, restrictions on possession of firearms in Marquesas are in place (Thorsen *et al.* 2002, p. 10). Hunting is not known to be a threat to the survival of this subspecies.

In addition, the entire Eiao Island was declared an officially protected area in 1971. It is classified as Category IV, an area managed for habitat or species. However, of the nine protected areas in French Polynesia, only one (Vaikivi on Ua Huka) is actively managed (Manu 2009, unpaginated). We found no information on the direct effects of this protective status on the Eiao reed-warbler or its habitat. However, Eiao Island is not actively managed and, as discussed under Factor A, the entire island has been heavily impacted by introduced domestic livestock, suggesting this regulatory mechanism is not effective at reducing or ameliorating threats to the species.

In summary, regulations exist that protect the subspecies and its habitat. However, as described under Factor A, habitat destruction continues to threaten this subspecies. Although legal protections are in place, there are none effectively protecting the suitable habitat on the island from damage from overgrazing sheep and other livestock as described in Factor A. Therefore, we find that the existing regulatory mechanisms are inadequate to ameliorate the current threats to the Eiao reed-warbler throughout its range.

E. Other Natural or Manmade Factors Affecting the Species' Continued Existence

Island populations have a higher risk of extinction than mainland populations. Ninety percent of bird species that have been driven to extinction were island species (as cited in Frankham 1997, p. 311). Based on genetics alone, endemic island species are predicted to have higher extinction rates than nonendemic island populations (Frankham 2007, p. 321). Small, isolated populations may experience decreased demographic viability (population birth and death rates, immigration and emigration rates, and sex ratios), increased susceptibility of extinction from stochastic environmental factors (*e.g.,* weather events, disease), and an increased threat of extinction from genetic isolation and subsequent inbreeding depression and genetic drift.

Because the population of Eiao reed-warblers is restricted to only one small island, it is vulnerable to stochastic events. Furthermore, the warblers are limited to the fraction of the island's area that contains suitable habitat. Eradication of feral livestock is needed to allow recovery of native vegetation and provide additional suitable habitat throughout the island. Expansion and recovery of native vegetation will permit the subspecies to recover beyond the current population of 2,000 individuals and buffer the subspecies against impacts from stochastic events.

In summary, the limited range of the Eiao reed-warbler makes this subspecies extremely vulnerable to stochastic events and, therefore, extinction. Additional habitat is needed to expand the population and buffer the subspecies from the detrimental effects typical of small island populations. Therefore, we find that other natural or manmade factors threaten the continued existence of the Eiao reed-warbler throughout its range.

Status Determination for the Eiao Marquesas Reed-Warbler

We have carefully assessed the best available scientific and commercial information regarding the past, present, and potential future threats faced by the Eiao Marquesas reed-warbler. The subspecies is currently at risk on Eiao Island due to ongoing threats of habitat destruction and modification (Factor A) and stochastic events associated with the subspecies' restricted range (Factor E). Furthermore, we have determined that the existing regulatory mechanisms (Factor D) are not adequate to ameliorate the current threats to the subspecies.

Section 3 of the Act defines an ''endangered species'' as ''any species which is in danger of extinction throughout all or a significant portion of its range,'' and a ''threatened species'' as ''any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.''

The estimated 2,000 Eiao reed-warblers are isolated on one 40 km^2 (15 mi^2) island, of which only 10–20 percent contains suitable habitat. The ongoing habitat degradation from overgrazing livestock prevents recovery of native vegetation. Although the current estimated population is 2,000 individuals, without active management of the feral livestock population on the island, the population of Eiao reed-warblers will continue to be restricted to small portions of the island and will not be able to expand to the rest of the island and recover beyond this current population level. Because the Eiao reed-warbler is limited to one small island, the continuing loss of habitat makes this subspecies extremely vulnerable to stochastic events and extinction. Island populations are naturally at a higher risk of extinction. Detrimental effects typical of small island populations, such as, decreased demographic viability, environmental factors, and genetic isolation, may lead to inbreeding depression and reduced fitness. These genetic threats will exacerbate other threats to the species and likely increase the risk of extinction. There are regulatory mechanisms in place, but are inadequate to protect the Eiao reed-warbler's habitat from overgrazing and eradication of native species. Without regulatory mechanisms to reduce or ameliorate these threats, negative impacts to this subspecies will continue. Based on the magnitude of overgrazing livestock to the extremely restricted range and isolated population of the Eiao Marquesas reed-warbler, as described above, we determine that this subspecies is in danger of extinction throughout all of its range. Therefore, on the basis of the best available scientific and commercial information, we are listing the Eiao Marquesas reed-warbler as an endangered subspecies throughout all of its range. Because we find that the Eiao Polynesian warbler is endangered throughout all of its range, there is no reason to consider its status in a significant portion of its range.

III. Greater Adjutant (*Leptoptilos dubius*)

Species Description

The greater adjutant (*Leptoptilos dubius*) is a very large (145 to 150 cm long (4.7 to 4.9 ft)) species of stork in the family Ciconiidae. This species is characterized by a naked pink head and a low-hanging neck pouch. Its bill is very thick and yellow in color. The plumage ruff of the neck is white, and other than a pale grey leading edge on each wing, the rest of the greater adjutant's body is dark grey (Birdlife International (BLI) 2009a, unpaginated).

This species of bird once was common across much of Southeast Asia, occurring in India, Bangladesh, Burma, Thailand, Cambodia, Malaysia, Myanmar, Vietnam, Sumatra, Java, and Borneo. Large breeding colonies occurred in Myanmar, with the highest concentration found in Pegu; however, this colony collapsed in the mid-1900s (Singha and Rahmani 2006, p. 264).

The current distribution of this species consists of two breeding populations, one in India and the other in Cambodia. Recent sighting records of this species from the neighboring countries of Nepal, Bangladesh, Vietnam, and Thailand are presumed to be wandering birds from one of the two populations in India and Cambodia (BLI 2009a, unpaginated).

India: The most recent range-wide population estimate for this species in India (600 to 800 birds) comes from data collected in 1995 through 1996 (Singha *et al.* 2003, p. 146). Approximately 11 breeding sites are located in the Brahmaputra Valley in the State of Assam (Singha *et al.* 2003, p.147). Recent information indicates that populations of this species continue to decline in India. At two breeding sites near the city of Guwahati in the State of Assam, the most recent survey data show that the number of breeding birds has declined from 247 birds in 2005 to 118 birds in 2007 (Hindu 2007, unpaginated).

In India, much of the greater adjutant's native habitat has been lost. The greater adjutant uses habitat in three national parks in India; however, almost all nesting colonies in India are found outside of the national parks. The greater adjutant often occurs close to urban areas; the species feeds in and around wetlands in the breeding season, and disperses to scavenge at trash dumps, burial grounds, and slaughter houses at other times of the year. The natural diet of the greater adjutant consists primarily of fish, frogs, reptiles, small mammals and birds, crustaceans, and carrion (Singha and Rahmani 2006, p. 266).

This species breeds in colonies during the dry season (winter) in stands of tall trees near water sources. In India, the greater adjutant prefers to nest in large, widely branched trees in a tightly spaced colony with little foliage cover and food sources nearby (Singha *et al.* 2002, p. 214). The breeding sites are also commonly associated with bamboo forests which provide protection from heavy rain during the pre-monsoon season (Singha *et al.* 2002, p. 218). Each adult female greater adjutant commonly lays two eggs each year (Singha and Rahmani 2006, p. 266).

Cambodia: Currently there are two known breeding populations in Cambodia. The larger of these two populations occurs in the Tonle Sap Biosphere Reserve (TSBR) near Tonle Sap Lake and has recently been estimated at 77 breeding pairs (Clements *et al.* 2007, p. 7). The Tonle Sap floodplain (and associated rivers) is considered one of the few remaining remnants of freshwater swamp forest in the region. Approximately 5,490 km^2 (2,120 mi^2) of the freshwater swamp forest ecoregion is protected in Cambodia. Of this, the Tonle Sap Great Lake Protected Area (which includes the Tonle Sap floodplain) makes up 5,420 km^2 (2,092 mi^2) (WWF 2007, p. 3).

A smaller population of greater adjutants was recently discovered in the Kulen Promtep Wildlife Sanctuary in the Northern Plains of Cambodia. This population has been estimated at 40 birds (Clements 2008, pers. comm.; BLI 2009, unpaginated). Although other breeding sites have not yet been found in Cambodia, researchers expect that the greater adjutant may nest along the Mekong River in the eastern provinces of Mondulkiri, Ratanakiri, Stung Treng, and Kratie in Cambodia (Clement 2008, pers. comm.).

In Cambodia, the greater adjutant breeds in freshwater flooded forest, and disperses to seasonally inundated forest, tall wet grasslands, mangroves, and intertidal flats to forage. These forests are characterized by deciduous tropical hardwoods (Dipterocarpaceae family) and semi-evergreen forest (containing a mix of deciduous and evergreen trees) interspersed with meadows, ponds, and other wetlands (WWF 2006b, p. 1).

Conservation Status

The IUCN classifies the greater adjutant as critically endangered. In India, the greater adjutant is listed under Schedule I of the Indian Wildlife Protection Act of 1972. The species is not listed in the Appendices of CITES (*http://www.cites.org*).

Summary of Factors Affecting the Greater Adjutant

A. Present or Threatened Destruction, Modification, or Curtailment of Habitat or Range

India: The greater adjutant occurs in Kaziranga, Manas, and Diburu-Saikhowa National Parks. However, nearly all breeding sites for this species are located outside of protected areas (Singha *et al.* 2003, p. 148). The ongoing loss of habitat through conversion for development and agriculture, and the clearing of trees that are suitable for breeding sites, is a primary threat to the greater adjutant. The recent decline in the population at the breeding colonies near Guwahai, India, is believed to be caused by tree removal at the breeding site and filling of wetlands in an area near the city that had been used by the greater adjutant as feeding areas (Hindu 2007, unpaginated). These activities were undertaken for the purpose of expanding residential developments in the city. The species is also seasonally dependent on wetlands for forage. These sites are impacted in India by drainage, encroachment, and overfishing. For instance, some sites have reportedly experienced encroachment from rice cultivation (BLI 2001, p. 284).

Singha *et al.* 2002 (pp. 218–219) found that preferred nest trees were significantly larger and different in structure to non-nest trees near Nagaon in central Assam. The nest trees were large and widely branched with thin foliage cover (Singha *et al.* 2002, p. 214). Researchers believe that removal of preferred nesting trees at breeding may result in adjutants nesting in suboptimal trees at existing nest sites or relocating to other suboptimal nest sites. The trees and their limbs at suboptimal breeding sites are smaller in diameter, and the structure of the limbs does not always support the combined weight of the nest, adults, and chicks. As chicks grow older, nest limbs often break, sending the half-grown chicks tumbling from the nest. Approximately 15 percent of chicks die after falling from their nests, for a variety of causes, including injuries and abandonment (Singha *et al.* 2006, p. 315). Some efforts have been made to reduce chick mortality, like those employed at two breeding sites near Nagaon from 2001 to 2003 (Singha *et al.* 2006, pp. 315–320). Safety nets are placed under the canopy of nest trees to catch falling chicks. Chicks are either replaced in their nest, if onsite monitors can determine which nest the chick came from, or raised in captivity and later released. Juvenile birds were monitored after their release, and the program is considered a success (Singha and Rahmani 2006, p. 268; Singha *et al.* 2006, pp. 315–320). Though some efforts have been undertaken to reduce chick mortality due to falls from nests, loss of chicks based on nesting in suboptimal breeding sites is likely still occurring at other breeding sites.

Cambodia: The largest breeding colonies are located in the Tonle Sap Biosphere Reserve, which consists primarily of the Tonle Sap Lake and its floodplain. A second breeding population occurs in the Kulen Promtep Wildlife Sanctuary in the Northern Plains. Poole (2002, p. 35) reported that large nesting trees around Cambodia's Tonle Sap floodplain, particularly crucial to greater adjutants for nesting, are under increasing pressure by felling for firewood and building material. Poole (2002, p. 35) concluded that a lack of nesting trees, both at Tonle Sap and in the Northern Plains, may be the most serious threat in the future to large water bird colonies.

The Mekong River Basin flows through several countries in Southeast Asia, including Tibet, China, Myanmar, Vietnam, Thailand, Cambodia, and Laos, traveling over 4,800 km (2,980 mi) from start to finish. In Cambodia, the Mekong River flows into the Tonle Sap floodplain. Tonle Sap Lake expands and contracts throughout the year as a result of rainfall from monsoons and the flow of the Mekong River. The lake acts as a storage reservoir at different times of the year to regulate flooding in the Mekong Delta (Davidson 2005, p. 3). This flooding also results in flooded forests and shrublands, which provides seasonal habitat to several species. The Tonle Sap Biosphere Reserve is one of Southeast Asia's most important wetlands for biodiversity and is particularly crucial for birds, reptiles, and plant assemblages (Davidson 2005, p. 6).

Upstream developments in the Mekong have already led to significant trapping of sediments and nutrients in upstream reservoirs, which could lead to increased bed and bank erosion downstream, as well as decreased productivity (Kummu and Varis 2007, pp. 289, 291). According to the Asian Development Bank (ADB 2005, p. 2), 13 dams have been built, are being built, or are proposed to be built along the Mekong River. Proposed hydroelectric dams along the Mekong River in countries upstream from Cambodia have the potential to adversely affect the habitat of the greater adjutant by affecting the hydrology of the basin and reducing the overall foraging habitat and the abundance of prey species during the breeding season (Clements *et al.* 2007, p. 59). In addition, decline in productivity of the habitat, and thereby prey species abundance, may increase competition for food, and increased releases from upstream dams during the dry season could result in permanent flooding of these forests that will eventually kill the trees in these areas (Clements *et al.* 2007, p. 59). Under some scenarios, up to half of the core area (21,342 ha (52,737 ac)) of the Prek Toal area in the Tonle Sap Biosphere Reserve could be affected.

In summary, this species continues to face significant ongoing threats to its breeding and foraging habitat in both India and Cambodia. In India, activities such as the draining and filling of wetlands (Hindu 2007, unpaginated), removal of nest trees, and encroachment on habitat significantly impact this species (BLI 2001, p. 284). In Cambodia, threats include tree removal (Poole 2002, p. 35) and large-scale hydrologic changes due to existing dams and proposed dam construction (Clements *et al.* 2007, p. 59; Kummu and Varis, pp. 287–288). The latter threat could potentially eliminate habitat in protected areas such as the Tonle Sap Biosphere Reserve, and it could additionally reduce productivity of these areas, which would further impact the species by affecting the foraging base and potentially increasing competition with other species (Clements *et al.* 2007, p. 59). Therefore, we find that the present or threatened destruction, modification, or curtailment of the habitat or range is a threat to the continued existence of the greater adjutant throughout its range.

B. Overutilization for Commercial, Recreational, Scientific, or Educational Purposes

The main threat to the greater adjutant is harvesting of eggs, chicks, or young fledglings (Clements 2008, pers. comm.). Local communities collect bird eggs and chicks for consumption and for trade in both India and Cambodia. Due to their rarity, greater adjutants are believed to have a high market value, which increases the likelihood this type of activity will continue. The implementation of bird nest protection programs has been developed by the Wildlife Conservation Society. Local people have been employed as nest protectors at Prek Toal and Kulen Promtep Wildlife Sanctuary (ACCB 2009, unpaginated; Clements 2008, pers. comm.). Although the impacts from large-scale collection of bird eggs and chicks have been reduced through these programs, collection still remains a threat to the species. Furthermore, unprotected colonies are likely disturbed every year and may not successfully breed (Clements 2008, pers. comm.). At the largest breeding sites for this species in India, reproductive success is low, less than one chick per nest per year (Singha and Rahmani 2006, p. 264). Because the total population of the greater adjutant is fewer than 1,000 birds, the loss of any eggs or chicks in populations in India and Cambodia is a significant threat to the species.

Accounts of poisoning, netting, trapping, and shooting of adult birds were also reported at various locations in both India and Cambodia during the 1990s (BLI 2001, pp. 285–286). In India, some birds were shot because of perceived impact on fish stocks; others, in hunts (BLI 2001, p. 285). In Cambodia, some birds were captured to be sold as food and for use as pets, and some were also hunted (BLI 2001, p. 286). Birds are also likely inadvertently injured or killed as a result of destructive fishing techniques in Cambodia such as electro-fishing and the use of poisons (Clements 2008, pers. comm.). In a 1999 article, the *Phnom Penh Post* (as reported in Environmental Justice Foundation 2002, p. 25) reported that pesticides are used to kill both fish and wildlife species at Tonle Sap.

In summary, although we are unaware of any scientific or educational purpose for which the adjutant is used, local communities are known to collect bird eggs, chicks, and adults for consumption and other purposes (*e.g.,* pet trade and perceived threat to fish stocks) in either or both India or Cambodia (BLI 2001, pp. 285–286). Incidence of local residents collecting eggs and chicks for consumption has been reduced in some areas due to educational and enforcement programs, however, these impacts still occur. Therefore, we find that overutilization due to commercial and recreational purposes is a threat to the continued existence of the greater adjutant throughout its range.

C. Disease or Predation

Highly pathogenic avian influenza (HPAI) H5N1 continues to be a serious problem for this species. This strain of avian influenza first appeared in Asia in 1996, and spread from country to country with rapid succession as found by Peterson *et al.* (2007, p. 1). By 2006, the virus was detected across most of Europe and in several African countries. Influenza A viruses, to which group strain H5N1 belongs, infects domestic animals and humans, but wildfowl and shorebirds are considered the primary source of this virus in nature (Olsen *et al.* 2006, p. 384). Though it is still unclear if the greater adjutant is a carrier, lack of an avian influenza wild bird surveillance program in Cambodia will make it difficult to resolve this question.

Until recently, there was no information on predation affecting the greater adjutant. However, recent research on other waterbirds suggests that predation may impact the greater adjutant in Cambodia. For example, nesting surveys for several waterbirds were conducted between 2004 and 2007 at the Prek Toal area in Tonle Sap Biosphere Reserve. These surveys included monitoring of nest sites. Human disturbances at nest sites due to illegal collection of chicks and eggs resulted in an increase of predation by crows (*Corvus* spp.) on spot-billed pelicans in the 2001–2002 breeding season, causing up to 100 percent loss of reproduction, and again in the 2002–2003 breeding season, resulting in up to 60 percent loss in reproduction due to a combination of collection and predation. In some locations, the spot-billed pelicans abandoned their nests for the remainder of the breeding season (Clements *et al.* 2007, p. 57). It is likely that other waterbirds, such as the greater adjutant, at Prek Toal would be similarly affected due to illegal collection of eggs by humans and nest site disturbance (see Factor B), and the subsequent increase in crow presence, thereby increasing the predation of their chicks and eggs.

In summary, we found no information indicating that avian diseases are impacting greater adjusts. However, research on other waterbirds in the same area as the greater adjutant found a significant impact on reproduction from predation by crows. Presence of crows was found in conjunction with human disturbances, such as illegal collection of eggs and chicks. Greater adjutant eggs and chicks are known to also be subjected to this type of human disturbance (See Factor B); therefore greater adjutants may also suffer impacts from predation by crows. Because the total population of the greater adjutant is fewer than 1,000 birds, and reproductive success for this species at the largest breeding sites in India is less than one chick per nest per year, the loss of any eggs and chicks in populations in India and Cambodia is a significant threat to the species. Therefore, we find that predation is a threat to the continued existence of the greater adjutant throughout its range.

D. Inadequacy of Existing Regulatory Mechanisms

Although there is evidence of commercial trade across the Cambodia border into Laos and Thailand, this species is currently not listed under CITES.

India: The greater adjutant is listed under Schedule I of the Indian Wildlife Protection Act of 1972 (IWPA). Schedule I provides absolute protection, with the greatest penalties for offenses. This law prohibits hunting, possession, sale, and transport of listed species. The IWPA also provides for the designation and management of sanctuaries and national parks for the purposes of protecting, propagating, or developing wildlife or its environment. As stated above in Factor A, the ongoing loss of habitat through habitat conversion for development and agriculture is a primary threat to this species. Furthermore, greater adjutant eggs and chicks are known to be taken for local consumption and trade, and adult birds are known to be poisoned, netted, and trapped for various reasons. Therefore, this regulatory mechanism is not adequate to ameliorate these threats to this species.

Protected areas in India allow for regulated levels of human use and disturbance and are managed to prevent widespread clearing and complete loss of suitable habitat. Although the greater adjutant uses habitat in three national parks in India, almost all nesting colonies of this species in India are found outside of protected areas (Singha *et al.* 2003, p. 148). Some of the species' foraging areas are also located outside of protected areas. Ongoing loss of habitat through habitat conversion for development and agriculture is a primary threat to this species; therefore, it appears that regulatory mechanisms outside of protected areas, such as national parks, do not provide adequate protection of habitat for the greater adjutant.

Cambodia: Areas designated as natural areas by the Ministry of Environment, such as the Tonle Sap Biosphere Reserve, are to be managed for the protection of the natural resources contained within. Portions of the Biosphere Reserve have also been designated as areas of importance under the Convention of Wetlands of International Importance of 1971.

The Mekong River Commission (MRC) was formed between the governments of Cambodia, Lao PDR, Thailand, and Vietnam in 1995 as part of the Agreement on the Cooperation for the Sustainable Development of the Mekong River Basin. The signatories agreed to jointly manage their shared water resources and the economic development of the river (MRC 2007, p. 1–2). According to the Asian Development Bank, 13 dams have been built, are being built, or are proposed to be built along the Mekong River (ADB 2005, p. 2). The continued modification of greater adjutant habitat has been identified as a primary threat to this species (Factor A), and this regional regulatory mechanism is not effective at reducing that threat.

Several laws exist in Cambodia to protect the greater adjutant from two of the primary threats to the species: Habitat destruction and hunting. However, they are ineffective at reducing those threats. In Cambodia, Declaration No. 359, issued by the Ministry of Agriculture, Forestry and Fisheries in 1994, prohibits the hunting of greater adjutant. However, reports of severe hunting pressure within the greater adjutant's habitat exist and illegal poaching of wildlife in Cambodia continues (Bird *et al.* 2006, p. 23; Poole 2002, pp. 34–35; UNEP–SEF 2005, pp. 23, 27).

The Creation and Designation of Protected Areas regulation (November 1993) established a national system of protected areas. In 1994, through Declaration No. 1033 on the Protection of Natural Areas, the following activities were banned in all protected areas:

(1) Construction of saw mills, charcoal ovens, brick kilns, tile kilns, limestone ovens, tobacco ovens;

(2) Hunting or placement of traps for tusks, bones, feathers, horns, leather, or blood;

(3) Deforestation;

(4) Mining minerals or use of explosives;

(5) The use of domestic animals such as dogs;

(6) Dumping of pollutants;

(7) The use of machines or heavy cars which may cause smoke pollution;

(8) Noise pollution; and

(9) Unpermitted research and experiments.

In addition, the Law on Environmental Protection and Natural Resource Management of 1996 sets forth general provisions for environmental protection. Under Article 8 of this law, Cambodia declares that its natural resources (including wildlife) shall be conserved, developed, and managed and used in a rational and sustainable manner.

Protected Areas have been established within the range of the greater adjutant, such as the Tonle Sap Lake Biosphere Reserve. The Tonle Sap Great Lake protected area was designated a multipurpose protected area in 1993 (Matsui *et al.* 2006, p. 411). Under this decree, Multiple Use Management Areas are those areas which provide for the sustainable use of water resources, timber, wildlife, fish, pasture, and recreation; the conservation of nature is primarily oriented to support these economic activities. In 1997, the Tonle Sap region was nominated as a Biosphere Reserve under UNESCO's (United Nations Educational, Scientific and Cultural Organization) ''Man and the Biosphere Program.'' The Cambodian Government developed a National Environmental Action Plan (NEAP) in 1997, supporting the UNESCO site goals. Among the priority areas of intervention are fisheries and floodplain agriculture at Tonle Sap Lake, biodiversity and protected areas, and environmental education. NEAP was followed by the adoption of the Strategy and Action Plan for the Protection of Tonle Sap (SAPPTS) in February 1998 (Matsui *et al.* 2006, p. 411), and the issuance of a Royal Decree officially creating Tonle Sap Lake Biosphere Reserve (TSBR) on April 10, 2001. The royal decree was followed by a subdecree by the Prime Minister to establish a Secretariat, along with its roles and functions, for the TSBR with the understanding that its objectives could not be achieved without cooperation and coordination among relevant stakeholders (TSBR Secretariat 2007, p. 1).

Joint Declaration No. 1563, on the Suppression of Wildlife Destruction in the Kingdom of Cambodia, was issued by the Ministry of Agriculture, Forestry, and Fisheries in 1996. Although the Japan International Cooperation Agency (JICA 1999, p. 19) reported that this regulatory measure was ineffectively enforced, some strides have been made recently through the combined efforts of WCS, the Cambodian Government, and local communities at Tonle Sap Lake. WCS Cambodia (2009, unpaginated) reports that the illegal wildlife trade in Cambodia is ''enormous'' and driven by demand for meat and traditional medicines in Thailand, Vietnam, and China. Substantial progress has been made in protecting seven species of waterbirds at Prek Toal Core Area in the TSBR, increasing populations of some species tenfold by working with the primary management agencies and working at the field level to improve community engagement, law enforcement, and long-term research and monitoring (WCS Cambodia 2009, unpaginated).

The Forestry Law of 2002 strictly prohibits hunting, harming, or harassing wildlife (Article 49) (Law on Forestry 2003). This law further prohibits the possession, trapping, transport, or trade in rare and endangered wildlife (Article 49). However, to our knowledge, Cambodia has not yet published a list of endangered or rare species. Thus, this law is not currently effective at protecting the greater adjutant from threats by hunting.

In 2006, the Cambodian Government created Integrated Farming and Biodiversity Areas (IFBA), including over 161 km (100 mi) of grassland (over 30,000 ha (74,132 ac)) near Tonle Sap Lake to protect the Bengal florican, an endangered bird in that region (WWF 2006a, pp. 1–2). The above measures have focused attention on the conservation situation at TSBR and have begun to improve the conservation of the area and its wildlife there, but several management challenges remain. These challenges include overexploitation of flooded forests and fisheries; negative impacts from invasive species; lack of monitoring and enforcement; low level of public awareness of biodiversity values; and uncoordinated research, monitoring, and evaluation of species' populations (Matsui *et al.* 2006, pp. 409–418; TSBR Secretariat 2007, pp. 1–6).

Even though the wildlife laws discussed above exist, greater adjutant habitat within Cambodian protected areas faces several challenges. The legal framework governing wetlands management is institutionally complex. It rests upon legislation vested in government agencies responsible for land use planning (Land Law 2001), resource use (Fishery Law 1987), and environmental conservation (Environmental Law 1996, Royal Decree on the Designation and Creation of National Protected Areas System 1993); however, there is no interministerial coordinating mechanism nationally for wetland planning and management (Bonheur *et al.* 2005, p. 9). As a result of this institutional complexity and lack of defined jurisdiction, natural resource use goes largely unregulated (Bonheur *et al.* 2005, p. 9). Thus, the protected areas system in Cambodia is ineffective in removing or reducing the threats of habitat modification and hunting faced by the greater adjutant.

Existing regulatory mechanisms in both India and Cambodia are ineffective at reducing or removing threats to the species such as habitat modification and collection of eggs and chicks for consumption. Although progress has been made recently in the protection of nests and birds at specific locations, this has largely been driven by measures from the private sector. We believe that the inadequacy of regulatory mechanisms, especially with regard to lack of law enforcement and habitat protection, is a significant risk factor for the greater adjutant. Therefore, we find that existing regulatory mechanisms are inadequate to ameliorate the current threats to the greater adjutant throughout its range.

E. Other Natural or Man-Made Factors Affecting the Species' Continued Existence

India: Due to a lack of natural foraging areas and availability of native wildlife carcasses to feed upon, the greater adjutant is known to commonly forage in refuge dumps and slaughterhouses during certain times of the year. Researchers believe that along with the refuse at these sites, these birds are inadvertently ingesting household contaminants and plastics that can adversely affect their health and reproductive capability (Singha *et al.* 2003, p. 148; BLI 2009a, unpaginated). In addition, pesticide has been used in winter to kill fish at a national park in India, and may be a widespread practice throughout the Brahmaputra lowlands (BLI 2001, p. 287). As the remaining natural foraging habitat for this species continues to shrink, the level of foraging at refuge dumps and slaughterhouses is expected to increase, thereby increasing the incidence of greater adjutants ingesting contaminants at these sites. Also, the use of pesticides in and near water sources in the Brahmaputra lowlands may result in further contamination to the species.

Cambodia: Increasing use of agro-chemicals, especially pesticides, is a major concern in the TSBR and throughout Cambodia. A survey conducted of Cambodian agricultural practices in 2000 showed that 67 percent of farms used pesticides. Of these farms, 44 percent began using pesticides in the 1980s, and 23 percent began using them in the 1990s (Environmental Justice Foundation (EJF) 2002, p. 13). All of the pesticides used in Cambodia are produced outside of the country, and the labels, which include information on the appropriate use of these chemicals, are often not written in a language understandable to local villagers (EJF 2002, p. 18). A Food and Agriculture Organization of the United Nations (FAO) study found that only 1 percent of vegetable farmers received technical training in pesticide use (EJF 2002, p. 17). This problem often leads to overuse of these highly toxic compounds.

In Cambodia, organochlorine insecticides, such as dichloro-diphenyl-trichloroethane (DDT), and organophosphate insecticides such as methyl-parathion are commonly used. Organochlorine insecticides are known to accumulate in aquatic systems and concentrate in the organs of species of waterbirds such as the greater adjutant. The effects of persistent organic pesticides are variable depending on concentration and species, but can include direct mortality, feminization of embryos, reduced hormones for egg-laying, and egg-shell thinning (EJF 2002, p. 24).

In the 1970s and 1980s, agricultural use of DDT was banned in most developed countries; however, it is still used for agriculture in Cambodia. In recent years, mong bean farmers in Siem Reap province are estimated to have applied 10 tons of a pesticide mix of DDT, Thiodan (endosulfan), and methyl-parathion on fields that are submerged in the wet season and thus capable of polluting the Tonle Sap basin (EJF 2002, p. 25). In addition, methyl-parathion and endosulfan are used in illegal fishing (EJF 2002, p. 14). Methyl-parathion is considered highly toxic to birds and may take 2 weeks to degrade in lakes and rivers. The decline in the number of some bird species from around the Tonle Sap Lake may be partly due to pesticide poisoning (EJF 2002, p. 25). Further, because higher levels of persistent organochlorines have been recorded in freshwater fish and mussels than marine fish and mussels, the source of these compounds is likely inland watersheds (EJF 2002, p. 24). Although we could not locate any specific contaminant reports on the amount of these toxic chemicals found in greater adjutants based on the above data, it is likely that the persistent use of these compounds is contributing to the decline of this species.

In summary, the use of pesticides occurs in both India and Cambodia for a variety of reasons, including agriculture, fishing, and insect control. As human interactions with the adjutant continue to increase, the chances of poisoning of the species, both directly and indirectly, also continue to rise. Therefore we find that other natural or manmade factors affecting the continued existence of the species in the form of pesticide use and ingesting other contaminants is a threat to the greater adjutant throughout its range.

Status Determination for the Greater Adjutant

We have carefully assessed the best available scientific and commercial information regarding the past, present, and potential future threats faced by the greater adjutant. The species is currently at risk throughout all of its range due to ongoing threats of habitat destruction and modification (Factor A); overutilization for commercial, recreational, scientific, or educational purposes in the form of hunting, egg and chick collection, and trapping (Factor B); predation (Factor C); inadequacy of existing regulatory mechanisms (Factor D); and other natural or manmade factors affecting its continued existence in the form of toxic compounds and other contaminants (Factor E).

Section 3 of the Act defines an ''endangered species'' as ''any species which is in danger of extinction throughout all or a significant portion of its range,'' and a ''threatened species'' as ''any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.''

In both India and Cambodia, breeding and foraging areas continue to be threatened by draining and filling of wetlands, removal of nest trees, and encroachment on habitat. Within Cambodia, existing dam construction and proposed dam construction have and are likely to continue to cause large-scale hydrologic changes and potentially eliminate habitat in protected areas. The types of changes could result in decreased productivity in these areas and increase competition with other species. In addition, local communities are known to collect greater adjutant eggs, chicks, and adults for consumption, for use as pets, and because of perceived threats to fish stocks. The use of pesticides occurs in both India and Cambodia for a variety of reasons, including agriculture, fishing, and insect control. As human interactions with the adjutant continue to increase, the chances of poisoning the species also continue to rise. Existing regulatory mechanisms are ineffective at reducing or removing threats to the species. Lack of enforcement and habitat protection is a significant threat to the species. Furthermore, with a population estimated at fewer than 1,000 birds, loss of eggs, chicks, or adults is a significant threat to the survival of this species. Based on the magnitude of the ongoing threats to the small population of greater adjutant and its habitat throughout its entire range, as described above, we determine that this species is in danger of extinction throughout all of its range. Therefore, on the basis of the best available scientific and commercial information, we are listing the greater adjutant as an endangered species throughout all of its range. Because we find that the greater adjutant is endangered throughout all of its range, there is no reason to consider its status in a significant portion of its range.

IV. Jerdon's Courser (*Rhinoptilus bitorquatus*)

Species Description

The Jerdon's courser, also known as the double-banded courser (*Rhinoptilus bitorquatus*), is a small, nocturnal bird, which is specialized for running and belongs to the family Glareolidae (Bhushan 1986, pp. 1, 6; Jeganathan *et al.* 2004a, p. 225; Jeganathan *et al.* 2004b, p. 7). It was first described by T. C. Jerdon in 1848 (Bhushan 1986, p. 1; Jeganathan *et al.* 2004b, p. 1). This species averages 27 cm (11 in) in length, its plumage consists of a brown breast with two narrow white bands (bordered with black) below an orange-chestnut gorget (throat patch), a blackish colored crown with a white coronal stripe, a broad buff-colored supercilium (eyebrow stripe) over a dark cheek-patch, white lores (space between the eye and bill), and a short yellow bill with a black tip (Rasmussen and Anderton 2005, p. 183; BLI 2009b, unpaginated). Males and females are not known to differ, and juvenile plumage is unknown (Rasmussen and Anderton 2005, p. 184).

The Jerdon's courser is a rare species of bird that is endemic to the Eastern Ghats of the states of Andhra Pradesh and extreme southern Madhya Pradesh in India (BLI 2009b, unpaginated). The size of the population is not known. Historically, this species was reported in the Khamman, Nellore, and Anantapur districts of Andhra Pradesh and the Gadchiroli District of Maharashtra (Jeganathan *et al.* 2005, p. 5). Until 1900, its presence was periodically recorded, including some records in the Pennar and Godavari river valleys and near Anantapur (Bhushan 1986, p. 2; Jeganathan *et al.* 2004a, p. 225; Jeganathan *et al.* 2004b, p. 7; Jeganathan *et al.* 2006, p. 227). Efforts by various ornithologists in the early 1930s and mid to late 1970s to record the presence of this species failed, leading to the belief that the species was extinct (Bhushan 1986, p. 2; Jeganathan *et al.* 2004b, p. 7). In 1986, the Jerdon's courser was rediscovered near Reddipalli village, Cuddapah District, Andhra Pradesh (Bhushan 1986, pp. 8–9; Jeganathan *et al.* 2004a, p. 225; Jeganathan *et al.* 2004b, p. 7; Jeganathan *et al.* 2005, p. 3; Jeganathan *et al.* 2006, p. 227; Senapathi *et al.* 2007, p. 1).

The area where the species was rediscovered was designated as the Sri Lankamaleswara Wildlife Sanctuary (SLWS) (Jeganathan *et al.* 2004b, p. 7; Jeganathan *et al.* 2005, p. 3). After its rediscovery, it was only observed regularly at a few sites in and around the SLWS (Jeganathan *et al.* 2004b, p. 7, 18; Jeganathan *et al.* 2005, p. 5; Jeganathan *et al.* 2006, p. 227; Senapathi *et al.* 2007, p. 1), including reports of its presence in Sri Penusula Narasimha Wildlife Sanctuary (SPNWS) in the Cuddapah and Nellore districts, Andhra Pradesh (Jeganathan *et al.* 2005, p. 3). It has since been found at three additional localities in and around SLWL (Jeganathan *et al.* 2004a, p. 228; Jeganathan *et al.* 2004b, p. 20; BLI 2009b, unpaginated).

Due to the nocturnal nature of the species and the wooded nature of its habitat, individuals are rarely seen; therefore, very little information is available on the distribution, ecology, population size, and habitat requirements of the Jerdon's courser (Jeganathan *et al.* 2004a, p. 225; Jeganathan *et al.* 2004b, p. 7; Jeganathan *et al.* 2005, p. 3; Jeganathan *et al.* 2006, p. 227; Senapathi *et al.* 2007, p. 1). New survey techniques have allowed researchers to detect the presence and absence of Jerdon's courser using track strips and a tape playback of the species' call. These methods can be useful in mapping the geographic range of the Jerdon's courser and in estimating the population size, and have contributed to a better understanding of habitat preferences. Surveys have not been conducted in all areas with suitable habitat characteristics; additional surveys are needed to confirm the current range and population size of this species. Although the size of the population is not known, it is believed to be a small, declining population (Jeganathan 2004b, p. 7; BLI 2009b, unpaginated; IUCN 2009c, unpaginated).

The Jerdon's courser inhabits open patches within scrub-forest interspersed with patches of bare ground, in gently undulating, rocky foothills (Jeganathan *et al.* 2005, p. 5; Senapathi *et al.* 2007, p. 1). Studies show that this species is most likely to occur where the density of large bushes (greater than 2 m (6 ft) tall) ranges from 300 to 700 per ha (121–283 large bushes per acre) and the density of smaller bushes (less than 2 m (6 ft) tall) is less than 1,000 per ha (404 per acre) (Jeganathan *et al.* 2004a, p. 228; Jeganathan *et al.* 2004b, p. 22; Jeganathan *et al.* 2005, p. 5; Senapathi *et al.* 2007, p. 1). The dominant woody vegetation includes species of shrub, particularly *Zizyphus rugosa, Carissa carandas*, and *Acacia horrida* (Jeganathan *et al.* 2004a, p. 228; Jeganathan *et al.* 2004b, p. 22).

The amount of suitable habitat that existed for this species in 2000 was estimated to be approximately 3,847 km² (1,485 mi²) of scrub habitat in the Cuddapah and Nellore districts of the State of Andhra Pradesh (Senapathi *et al.* 2007, p. 6). Jeganathan (2008, pers. comm.) further stated that the amount of suitable habitat available in and around the SLWS is approximately 132 km² (51 mi²). A comprehensive habitat assessment of all the shrub habitat areas within the historic range of this species has not yet been completed; therefore, suitable habitat may occur elsewhere for this species.

Little information is known about feeding habits or feeding areas of this species. The only information known comes from the analysis of two Jerdon's courser fecal samples, which consisted mainly of termites and ants. Jeganathan (2004a, p. 234) suggested that despite being nocturnal and affected by the shadowing effects of the canopy, coursers may be able to see invertebrate prey on the ground by selecting relatively well-illuminated open areas.

There is no information on the life history of the Jerdon's courser; no nests or young birds have ever been found, although the footprints of a young bird along with an adult Jerdon's courser suggests successful breeding is taking place (Jeganathan *et al.* 2004b, pp. 17, 29). The calling period is brief, starting approximately 45 to 50 minutes after sunset and continuing for a few minutes to approximately 20 minutes.

Conservation Status

Due to the single, small, and declining population of the Jerdon's courser, it is classified as ''critically endangered'' by the IUCN (Jeganathan *et al.* 2004b, p. 7; Senapathi *et al.* 2007, p. 1; Jeganathan *et al.* 2008, p. 73; IUCN 2009c, unpaginated), a category assigned to species facing an extremely high risk of extinction in the wild. It is also listed under Schedule I of the Indian Wildlife Protection Act of 1972. The species has not been formally considered for listing in the Appendices of CITES (*http://www.cites.org*).

In 2010, a recovery plan was published for the Jerdon's courser. The goals of this plan are to ''secure the long-term future of the Jerdon's courser and the scrub forest it is found in'' and improve the conservation status of the Jerdon's courser within the next 10 years (2010–11 to 2020–21) (Anon 2010, p. 13). The Recovery Plan lays out objectives with specific actions to reach those objectives and includes a time scale and parties responsible for each action. Objectives include protection of existing habitat, locating suitable habitat and determining if the species occurs in those areas, research and monitoring to support conservation efforts and track populations and habitat changes, and raising awareness of the conservation issues (Anon 2010, p. 16).

Summary of Factors Affecting the Jerdon's Courser

A. Present or Threatened Destruction, Modification, or Curtailment of Habitat or Range

The primary threat to the persistence of the Jerdon's courser is habitat destruction and alteration due to conversion of suitable habitat to agriculture lands, grazing, and construction within and around the SLWS and SPNWS, and increasing settlements (Jeganathan 2005 *et al.* 2005, p. 6; Norris 2008, pers. comm.; Jeganathan 2009, pers. comm.). Agriculture is the main occupation of the people living in the area. The State of Andhra Pradesh has experienced growth of intensive agricultural practices in recent years (Senapathi *et al.* 2007, p. 2), with paddy (*Oryza sativa*), sunflower (*Helianthus annuus*), cotton (*Gossypium* sp.), groundnut (*Arachis hypogaea*), finger millet (*Eleusince coracana*), turmeric (*Curcuma longa*), and onion (*Allium cepa*) being the major crops of the area (Jeganathan *et al.* 2008, p. 77). From 1991 to 2000, scrub habitat in the Cuddapah District and parts of the Nellore District in Andhra Pradesh decreased by 11–15 percent, while the area occupied by agricultural land more than doubled (109 percent increase) during the same time period. Remaining scrub patches were also found to be smaller (38.4 percent decrease) and further from human settlements (Senapathi *et al.* 2007, pp. 1, 4; Jeganathan *et al.* 2008, p. 76).

The main causes for the loss of scrub habitat were human settlements and subsequent conversions of scrub habitat to agriculture and cleared areas (Senapathi *et al.* 2007, p. 6). From 2001 to 2004, an estimated 480 ha (1,186 ac) of scrub habitat were cleared within and around the SLWS, 275 ha (680 ac) of which were cleared to provide land for agriculture to the people who were displaced by floods and for farming of lemons and forestry plantations. These cleared areas fall within 1 km (0.6 mi) of previously known and newly discovered Jerdon's courser areas (Jeganathan *et al.* 2008, p. 76). From 2000 to 2005, Jeganathan *et al.* (2008, p. 77) noted that approximately 215 ha (531 ac) of scrub habitat outside of the SLWS were cleared and most likely will become lemon farms. The irrigation required to sustain agricultural activities will likely further fragment any remaining suitable habitat (Senapathi *et al.* 2007, p. 7).

The Jerdon's courser inhabits open patches within scrub-forest and prefers areas with moderate densities of trees and bushes (Jeganathan *et al.* 2004a, p. 234). Researchers believe this open habitat is maintained by grazing animals and some woodcutting (Norris 2008, pers. comm.). Known Jerdon's courser sites are already being used for grazing livestock and woodcutting, but at moderate levels that maintain the appropriate vegetation structure (Jeganathan 2005, p. 15). Mechanical clearing of bushes to create pasture, orchards, and tilled land; high levels of woodcutting; and high level of use by domestic livestock are likely to cause deterioration in scrub habitat by creating a scrub forest that is too open for the Jerdon's courser. However, low levels of grazing by livestock or absence of woodcutting may also lead to habitat that is more closed and, therefore, unsuitable (Jeganathan *et al.* 2004a, p. 234; Jeganathan *et al.* 2004b, p. 23; Norris 2008, pers. comm.).

Land in SLWS and adjacent areas is used by the people from villages in Sagileru valley for grazing herds of domestic buffalo (*Bubalus bubalis*), sheep (*Ovis aries*), and goats (*Capra hircus*), and for woodcutting (Jeganathan *et al.* 2004b, p. 9). Jeganathan (2008, pers. comm.) states that most of the potentially suitable habitat for Jerdon's courser is located on the fringe of the forest and can be easily accessed by locals for grazing and woodcutting. Jeganathan *et al.* (2008, p. 77) notes three types of grazing within and around the SLWS and SPNWS. The first includes shepherds who bring goats, sheep, and buffalo into the scrub habitat in and around the sanctuaries every morning, grazing 2–3 km (1–2 mi) into the forest before returning to the villages in the evening. The second includes nomads with 200–300 cattle. Although they are invited by farmers to help fertilize the lemon farms, they stay 3 to 4 months and graze in the forested areas in and around the sanctuaries. The third includes sheep that graze inside the sanctuaries throughout the year; however, this type of grazing did not occur in scrub habitat. Furthermore, a common practice is to cut and bend the branches of scrub and tree species to facilitate better access for grazing (Jeganathan *et al.* 2008, p. 78). In addition, the people of the local villages also use the sanctuaries for timber and nontimber forest products; including fuel wood, illegal wood collecting, grass, and bamboo. From 2001 to 2003, Jeganathan *et al.* (2008, pp. 77–78) regularly observed wood loads being removed by either head loads, bullock cart, or tractor.

Development activities within the SLWS, including the construction of check dams and percolation ponds and digging of trenches, have been observed in known and newly recorded areas of the Jerdon's courser (Jeganathan *et al.* 2004a, pp. 26, 28; Jeganathan *et al.* 2008, p. 76). Approximately 0.5 to 1 ha (1–2 ac) of scrub forest was cleared for each of five percolation ponds dug near the main Jerdon's courser area and exotic plant species planted on the embankment. In addition, scrub habitat was thinned (removal of all scrub species except selected tree saplings), and pits for collecting rainwater were dug (Jeganathan *et al.* 2008, p. 76). Furthermore, various sizes of stones were collected from the scrub jungle within and around the SLWS for road construction every year. Collection included digging of stones with crowbars, collection of stones in heavy vehicles, and the excavation of 15 large pits (Jeganathan *et al.* 2008, p. 76).

Construction of dams and reservoirs and river floods in the area has resulted in the relocation of villages near the SLWS and SPNWS. Fifty-seven villages were relocated closer to SLWS after the construction of the Somasila dam. Fifteen were displaced due to the construction of the Sri Potuluri Veera Brahmendraswamy (SPVB) Reservoir. Currently, there are approximately 146 villages between the SLWS and SPNWS (Jeganathan *et al.* 2008, pp. 76–77). There are more villages in the area of Somasila and SPVB Reservoir that could be relocated near the sanctuaries in the future, and there are plans to increase the height of the Somasila dam, which will cause the displacement of more villages near the southeastern part of SLWS (Jeganathan *et al.* 2008, p. 77). With the relocation and expansion of human settlements, there is concern over additional land conversion for agriculture, increased pressure for grazing and woodcutting, and further development.

At the time of the Jerdon's courser rediscovery in 1986, the only known site where the species was found was under threat from a project to construct the Telugu-Ganga canal through its habitat. The Andhra Pradesh Forestry Department (APFD) and the State Government of Andhra Pradesh responded by designating the site as the SLWS to protect the species. The proposed route of the canal was adjusted to avoid the sanctuary (Jeganathan *et al.* 2005, p. 6; Jeganathan *et al.* 2008, p. 78). However, in 2005, construction of the Telugu-Ganga canal began, illegally, within the SLWS. Construction was stopped immediately once the APFD was notified (Jeganathan *et al.* 2005, p. 6; Kohli 2006, unpaginated). Illegal excavation was reported even after construction was stopped and the contracting company fined (Kohli 2006, unpaginated).

Jeganathan *et al.* (2005, p. 12) found that 80 to 100 m (263 to 328 ft) were cleared for canals that were 16 to 20 m (53 to 66 ft) wide. They also found that approximately 22 ha (54 ac) of potentially suitable habitat were cleared and one of the three newly recorded sites for the Jerdon's courser was destroyed by the illegal construction within the SLWS (Jeganathan *et al.* 2005, p. 12; Jeganathan *et al.* 2008, p. 73). The potential impacts of the proposed realignment were also assessed and it was determined that the construction of the canal would still impact 650 ha (1,606 ac) of suitable habitat around the SLWS and would pass within 500 m (1640 ft) of recent records of the Jerdon's courser and pass very close to the only place where the species has been regularly sighted since 1986 (Jeganathan *et al.* 2005, p. 12; Jeganathan *et al.* 2008, p. 80). Plans for the Telugu-Ganga canal included another canal project along the western boundary of the SPNWS. Unauthorized work near the Sanctuary boundary was stopped by the Cuddapah Forest Division in October 2005. In some locations along the canal route, forest had been cleared and roads developed inside of the Sanctuary boundary (Jeganathan *et al.* 2005, p. 9). Approximately 163 ha (403 ac) were cleared for the construction of the canal in and around the SPNWS (Jeganathan *et al.* 2005; Jeganathan *et al.* 2008, p. 80). It is unknown how much of this area is occupied by the Jerdon's courser.

Following the illegal construction of the canal within the SLWS and SPNWS, the issue was raised to the Central Empowered Committee (CEC), a monitoring body on forest matters set up by the Supreme Court (Kholi 2006, unpaginated). The CEC ruled in favor of a realignment route completely avoiding courser habitat. Also, the government of Andhra Pradesh has transferred approximately 1,000 ha (2,4711 ac) of land between the canal and the SLWS to the APFD (BLI 2009b, unpaginated; Jeganathan 2009, pers. comm.).

During the construction of the Telugu-Ganga canal, Jeganathan *et al.* (2005, p. 13) identified additional threats in association with the construction. Roads were built along the canal route and from the main roads to the canal, which subsequently provided easy access to the forest for unauthorized woodcutting. Furthermore, the SLWS is known to have red sanders (*Pterocarpus santalinus*), a highly valued species of trees sought after by illegal woodcutters. APDF records from 1984 to 2003 show that more than 116,000 kilograms (255,736 pounds) of matured red sanders were seized from smugglers (Jeganathan *et al.* 2005, p. 13). Pressure from smugglers on mature red sanders, coupled with the increased access points into the SLWS due to canal construction activities, has caused extensive unauthorized woodcutting within the SLWS (Jeganathan *et al.* 2005, p. 13).

In summary, the scrub habitat known to be occupied by the species and potentially suitable habitat on adjacent lands in and around the SLWS and SPNWS in the Cuddapah District of India have been destroyed and diminished due to conversion of land for agricultural purposes, grazing livestock, construction, and woodcutting. These actions are a result of human expansion and the subsequent increase in human activity in and around the SLWS and SPNWS. Additional relocation of villages around SLWS and SPNWS is anticipated. Because the two most common livelihoods are agriculture and cattle rearing and because the establishment of additional villages will require more land to accommodate agriculture and livestock needs, the scrub habitat that is vital to the Jerdon's courser remains at risk of further curtailment. The population of the Jerdon's courser is extremely small and believed to be declining, so any further loss or degradation of remaining suitable habitat represents a significant threat to the species. Therefore, we find that present or threatened destruction, modification, or curtailment of the habitat or range are threats to the continued existence of the Jerdon's courser throughout its range.

B. Overutilization for Commercial, Recreational, Scientific, or Educational Purposes

Jeganathan *et al.* (2008, p. 78) noted a few encounters with illegal bird trapping within the peripheral areas of the eastern part of the SLWS; on one occasion a trapper was seen near the main Jerdon's courser area. Although trappers mainly target other species, such as Grey partridge (*Francolinus pondicerianus*) and Quail species, the traps consist of nooses and nets in which the Jerdon's courser could potentially get caught (Jeganathan *et al.* 2008, p. 78). However, there is no quantitative information on which to analyze the extent to which this threat may be acting on this species. In addition, we are not aware of any information currently available that indicates the use of this species for any scientific or educational purpose. As a result, we are not considering overutilization to be a contributing threat to the continued existence of the Jerdon's courser throughout its range.

C. Disease or Predation

We are not aware of any information currently available that indicates disease or predation pose a threat for this species. As a result, we are not considering disease or predation to be contributing threats to the continued existence of the Jerdon's courser throughout its range.

D. Inadequacy of Existing Regulatory Mechanisms

The Jerdon's courser is listed under Schedule I of the Indian Wildlife Protection Act of 1972. Schedule I provides absolute protection with the greatest penalties for offenses. This law prohibits hunting, possession, sale, and transport of listed species and allows the State Government to designate an area as a sanctuary or national park for the purpose of protecting, propagating, or developing wildlife or its environment. The Jerdon's courser is also listed as a priority species under the National Wildlife Action Plan (2002–2016) of India. This National Plan includes guidance to expand and strengthen the existing network of protected areas, develop management plans for protected areas in the country, restore and manage degraded habitats outside of protected areas, and control activities such as poaching and illegal trade, among others. We are unaware of any management plans for the protected areas in Andhra Pradesh where the Jerdon's courser occurs. This species is also proposed as a threatened species under section 38 of the Biological Diversity Act, 2002 (Anon 2010, p. 6).

The SLWS and SPNWS were established for the purpose of protecting the habitat of the Jerdon's courser. The sanctuaries allow for regulated levels of human use and disturbance while preventing complete loss of scrub habitat (Senapathi *et al.* 2007, p. 8). The SLWS and SPNWS are protected by the Forest Conservation Act of 1980. Section 2 of this law restricts the use of forest land for nonforest purposes, such as the fragmentation or clearing of any forest. In addition, the SLWS and SNPWS are designated as Important Bird Areas (IBA) in India (Jeganathan *et al.* 2005, p. 5). IBAs are sites of international importance for the conservation of birds, as well as other animals and plants, and are meant to be used to focus conservation efforts and reinforce the existing protected areas network. However, designation as an IBA provides no legal protection of these areas (BNHS 2009, unpaginated).

In 2010, a recovery plan was published for the Jerdon's courser. The plan uses a multi-pronged approach to secure the long-term survival of this species. Elements of the plan include research, monitoring, advocacy, conservation education, habitat management, training, and funding. The actions outlined in the plan involve several national and international groups and the APFD, which has the primary responsibility for the management of Jerdon's courser habitat (Anon 2010, pp. 3, 5). Implementation of the recovery plan is dependent on funding (approximately 1.8 million U.S. dollars) and the cooperation of several agencies (Anon 2010, pp. 16–21). Although this plan was published by the APFD and submitted to The Ministry of Environment and Forests, Government of India, we could not determine that implementation of this plan is mandatory or binding; rather the plan is meant to serve as a reference for conservation managers, policy-makers, researchers, decision-makers, and serve as a basis for future conservation actions. Furthermore, as this recovery plan was just published in November 2010, it is too early to determine if this plan will be effective in providing protection to the species.

In summary, although protections for the species exist, the primary threat to this species is ongoing loss of habitat. Senapathi *et al.* (2007, pp. 7–8) found an extensive and rapid decline in scrub habitat, with most removal of scrub occurring up to sanctuary boundaries and little loss occurring within the wildlife sanctuaries. Due to the threat of an increasing number of settlements near the sanctuaries, and the subsequent further loss of scrub habitat to agriculture and livestock, protection of scrub habitat used by the Jerdon's courser will be important for the species' continued existence. Jeganathan *et al.* (2004, p. 28) classified many areas in the Cuddapah District as suitable habitat for the Jerdon's courser; however, with the exception of two sanctuaries, the rest of the suitable habitats are not protected. Therefore, current regulatory mechanisms do not provide enough protection of suitable habitat for this species outside of existing protected areas. We are also unaware of any grazing standards within SLWS and SPNWS to ensure the maintenance of open scrub habitat and prevent overgrazing by livestock. When combined with Factor A (the present or threatened destruction, modification, or curtailment of the habitat or range), we find that the existing regulatory mechanisms are inadequate to ameliorate the current threats to the Jerdon's courser throughout its range.

E. Other Natural or Manmade Factors Affecting the Species' Continued Existence

There are particular species characteristics that render a species vulnerable to extinction (Primack 2002, p. 193). For example, species with a narrow geographic range, small population size, declining population, and specialized habitat requirements are more susceptible to extinction than others without these characteristics (Primack 2002, pp. 193–200). Although exact population estimates and distribution of the Jerdon's courser are not available, the species has been reported as a small, declining population (Jeganathan 2004b, p. 7; BLI 2009b, unpaginated; IUCN 2009c, unpaginated) and only reported from a small patch of scrub habitat in and around the SLWS (Jeganathan *et al.* 2008, p. 73). Furthermore, certain species characteristics, such as those found in this species, predispose it to particular sources of extinction (Owens and Bennett 2000, p. 12147). Owens and Bennett (2000, p. 12147) found that extinction risks for birds with specialized habitat and small body size increased with habitat loss. The Jerdon's courser is a small bird dependent on scrub habitat of moderate density for survival. Habitat loss, as described under Factor A, is the primary threat to this species. Further loss of Jerdon's courser habitat may fragment remaining suitable habitat adjacent to the SLWS and increase the extinction risk for the species. In addition, small, isolated populations may experience decreased demographic viability and increased susceptibility to extinction from stochastic environmental factors (*e.g.,* weather events, disease) and an increased threat of extinction from genetic isolation and subsequent inbreeding depression and genetic drift.

In conclusion, the single known population of Jerdon's courser is likely to be vulnerable to threats associated with low population sizes. Because the known population is small in size, and restricted in range, and depends on a special habitat for survival, any factor (*i.e.,* habitat change, a loss of demographic viability, *etc.*) that results in a decline in habitat or individuals is problematic for the long-term survival of this species. Therefore, we find that other natural or manmade factors pose a threat to the Jerdon's courser throughout its range.

Status Determination for the Jerdon's Courser

We have carefully assessed the best available scientific and commercial information regarding the past, present, and potential future threats faced by the Jerdon's courser. The species is currently at risk throughout all of its range due to ongoing threats of habitat destruction and modification (Factor A), and demographic, genetic, and environmental stochastic events and other complications associated with the species' low population and restricted range (Factor E). Furthermore, we have determined that the existing regulatory mechanisms (Factor D) are not adequate to ameliorate the current threats to the species.

Section 3 of the Act defines an "endangered species" as "any species which is in danger of extinction throughout all or a significant portion of its range" and a "threatened species" as "any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range."

Known occupied habitat and potentially suitable habitat have already been destroyed and diminished due to conversion of land for agriculture, grazing livestock, construction, and wood cutting. Additional relocation of villages around the SLWS and SPNWS is anticipated. The two most common livelihoods for people in this region are agriculture and cattle rearing; relocation of villages will require the conversion of additional land to accommodate these needs. Currently, there are protections in place for this species, but these do not provide enough protection to suitable habitat outside of protected areas. Within protected areas, grazing still occurs and there are no grazing standards in place to ensure maintenance of open scrub habitat. Characteristics of the Jerdon's courser, such as small body size, small population, declining population, narrow geographic range, and specialized habitat requirements, naturally put this species more at risk of extinction.

Any factor (*i.e.,* habitat change, a loss of demographic viability, *etc.*) that results in a decline in habitat or individuals is problematic for the long-term survival of this species. Decreased demographic viability, environmental factors, and genetic isolation may lead to inbreeding depression and reduced fitness. These genetic threats will exacerbate other threats to the species and likely increase the risk of extinction. Based on the magnitude of the ongoing threats to the Jerdon's courser habitat throughout its entire range, as described above (Factor A and D), combined with the small population, restricted range, and specialized habitat requirements (Factor E), we determine that this species is in danger of extinction throughout all of its range. Therefore, on the basis of the best available scientific and commercial information, we are listing the Jerdon's courser as an endangered species throughout all of its range. Because we find that the Jerdon's courser is endangered throughout all of its range, there is no reason to consider its status in a significant portion of its range.

V. Marquesan Imperial Pigeon (*Ducula galeata*)

Species Description

The Marquesan Imperial Pigeon (*Ducula galeata*), known locally as Upe, is a very large arboreal pigeon belonging to the family Columbidae. It was first described by Charles Lucien Bonaparte in 1855 (Villard *et al.* 2003, p. 198; BLI 2009c, unpaginated). The species measures 55 cm (22 in) in length, is dark slate-grey with bronze-green reflections on the upperparts, rufous-chestnut undertail-coverts, white eyes, and a white and grey-black cere protruding almost to the tip of the bill (Blanvillain *et al.* 2007, unpaginated; BLI 2009c, unpaginated).

The pigeon is endemic to the French Polynesian Marquesas Archipelago in the Pacific Ocean. The Marquesas Archipelago is a territory of France located approximately 1,600 km (994 mi) northeast of Tahiti. Based on subfossil records, the pigeon was historically present on four islands in the Marquesas Archipelago, Hiva Oa, Ua Huka, Tahuata, and Nuku Hiva, as well as the Cook, the Pitcairn, and Society Island chains (Steadman 1997, p. 740; Thorsen *et al.* 2002, p. 6; Blanvillain and Thorsen 2003, p. 381; Blanvillain *et al.* 2007, unpaginated). At the time of its discovery, the pigeon was already restricted to Nuku Hiva, a 337 km^2 (130 sq mi^2) island. Researchers believe that hunting, degradation of local forest, invasive weeds and trees, and predation were the probable causes of its decline (Thorsen *et al.* 2002, pp. 8–9; Blanvillian *et al.* 2007, unpaginated). On Nuku Hiva, the pigeon is restricted to 7 sites which are difficult to access by hunters and livestock (Villard *et al.* 2003, p. 191; BLI 2009c, unpaginated). In an effort to protect the remaining population from extinction due to catastrophic events, the pigeon was reintroduced to Ua Huka, an island 50 km (31 mi) east of Nuku Hiva in 2000 (Thorsen *et al.* 2002, p. 14; Blanvillain and Thorsen 2003, p. 385; BLI 2009c, unpaginated). Ua Huka was chosen as a reintroduction site primarily because the pigeon was historically found on the island, and due to availability of suitable habitat located in a protected area, a lack of black rats (*Rattus rattus*), and a smaller human population compared to other Marquesan islands (Thorsen *et al.* 2002, p. 13).

Population estimates on Nuku Hiva have ranged from 75 to 300 birds since 1975; however, the most recent survey, conducted in 2000, estimated the population to be approximately 80–150 birds (Villard *et al.* 2003, p. 194). In 2000, five birds were translocated to Ua Huka and an additional five translocated in 2003. In 2006, approximately 32 birds were present. In 2008, another survey was conducted. Two groups of nine and six birds were observed within the initial translocation area (Gouni and Gustemme 2009, p. 4). Gouni and Gustemme (2009, p. 4) suggest that the population has expanded into inaccessible parts of the island where surveys are not possible and further speculate that, given the lack of limiting factors on the island, the population may have already reached 50 individuals.

The species is almost exclusively arboreal and prefers the intermediate and upper canopy forest layers consisting of *Guettarda speciosa, Cerbera manghas, Ficus* spp., *Terminalia cattapa,* and *Sapindus saponaria;* however, individuals have also been observed perched on shrubs (Blanvillain and Thorsen 2003, p. 382; Villard *et al.* 2003, p. 191). These pigeons heavily rely on this canopy forest for roosting and feeding. Based on observations of pigeons in 2000, this species appears to return to the same feeding and night roosting areas.

Species of *Ducula* are primarily frugivorous (fruit eaters). The diet of Marquesan imperial pigeons consists mainly of fruits, which are usually swallowed whole, from *Ficus* spp. and *Psidium guajava* (guava; an introduced species); however, it has been reported that caterpillars from *S. saponaria* and the foliage and flowers of other tree and shrub species also make up a portion of the pigeon's diet. The species' consumption of an introduced shrub species, the guava, is likely due to the degradation of native habitat (Blanvillain and Thorsen 2003, p. 384) and the subsequent loss of native fruits, foliage, and flowers. Gleaning, the catching of invertebrate prey items by plucking them from foliage, the ground, or from rock crevices, and browsing are the two main feeding methods (Blanvillain and Thorsen 2003, pp. 382–383).

Courtship behavior includes the male and female sitting next to one another and allopreening, preening the potential mate's breast and neck areas and mirroring each other's actions (Blanvillain and Thorsen 2003, p. 383). The breeding season is long, occurring from mid-May to December (Thorsen *et al.* 2002, p. 6). Nests are constructed of intermingled branches, approximately 60 cm (24 in) in diameter, 10 to 18 m (33 to 59 ft) above ground at the top of the canopy (Blanvillain and Thorsen 2003, p. 384); clutch size is only one egg (Villard *et al.* 2003, pp. 192, 195). Abundance of fruit is critical in determining the breeding success of frugivorous birds (Thorsen *et al.* 2002, p. 10). However, studies suggest that the pigeon is successfully breeding in different areas where it exists (Thorsen *et al.* 2002, p. 17; Villard *et al.* 2003, p. 195).

Conservation Status

The Marquesan imperial pigeon was originally classified as ''critically endangered'' by the IUCN. In 2008, however, this species was downlisted to ''endangered'' status due to the establishment of a second population through the translocation of birds to Ua Huka (IUCN 2009b, unpaginated). The Marquesan imperial pigeon is also protected under Law Number 95–257 in French Polynesia. The species has not been formally considered for listing in the Appendices of CITES (*http://www.cites.org*).

Summary of Factors Affecting the Marquesan Imperial Pigeon

A. Present or Threatened Destruction, Modification, or Curtailment of Habitat or Range

Destruction of habitat associated with human colonization is one of the main threats to the remaining populations of the Marquesan imperial pigeon. Since Polynesian occupation and discovery of the area by Europeans, substantial changes to the Nuku Hiva landscape have occurred (Thorsen *et al.* 2002, p. 8; Villard *et al.* 2003, p. 190) and are still occurring. These changes include clearing of land for agriculture and development, introduction of domestic livestock, introduction of exotic plants, and introduction of rats (*Rattus* spp.) and cats (*Felis catus*) (Thorsen *et al.* 2002, pp. 8–9).

Most of Nuku Hiva was originally covered by forest, with the exception of the drier northwestern plain where shrub savanna is predominant. Since colonization of Nuku Hiva, the native landscape has been cleared for agriculture and settlement. Fires have been used to clear land for agriculture and plantations (Manu 2009, unpaginated). In more recent times (between 1974 and 1989), all natural vegetation on a large area of the main plateau (de Toovii) on the island was cut down or burned to be converted into grassland for pasture, and 1,100 ha (2,718 ac) were planted with Caribbean pine (*Pinus caribaea*), an exotic tree species. By 2000, modern facilities, such as roads, an airport, and other buildings had been built (Villard *et al.* 2003, pp. 190, 195).

Suitable habitat for this species has also been modified and degraded by introduced domestic livestock and exotic plant species. Domestic livestock have become feral, and while cattle and horses are mostly controlled, feral goats (*Capra hircus*) and pigs (*Sus scrofa*) continue to be a major concern (Villard *et al.* 2003, p. 193). Goats are particularly destructive; they have caused devastation to natural habitats on several other islands (Sykes 1969, pp. 13–16; Parkes 1984, pp. 95–101; Thorsen *et al.* 2002, p. 9).

The Nuku Hiva goat population has been increasing since the 1970s, and both goats and pigs are found everywhere on the island (Villard *et al.* 2003, p. 195). Goats have the potential to damage and alter the vegetative composition of an area by overgrazing indigenous and endemic species to the point at which seedlings are consumed before they are able to mature to a height that is out of the reach of goats and, therefore, survive (Sykes 1969, p. 14; Parkes 1984, pp. 95, 96, 101; Villard *et al.* 2002, p. 189). Subsequently, exotic plant species are able to flourish and outcompete native species, which results in little or no regeneration of native trees (Sykes 1969, p. 15; Thorsen *et al.* 2002, p. 9). Large patches of natural forest have been destroyed by goats and pigs in areas where Marquesan imperial pigeons are found and there is poor natural forest regeneration (Villard *et al.* 2003, p. 193). Blanvillain and Thorsen (2003, pp. 382–383) found most of the ground covered by several introduced plant species, including guava, African basil (*Ocimum gratissimum*), and soft elephants foot (*Elephantopus mollis*). Overgrazing, combined with the introduction of exotic species, prohibits the tall trees that comprise the canopy layer of the forest from regenerating and from providing feeding and roosting sites needed by pigeons.

In addition, introduced rats on the island of Nuka Hiva inhibit regeneration of native trees because they consume the flowers, fruits, seeds, seedlings, leaves, buds, roots, and rhizomes (Thorsen *et al.* 2002, p. 9; Meyer and Butaud 2009, p. 1570), thus further contributing to the alteration of the vegetation composition. Thorsen *et al.* (2002, p. 9) noted that seed caches containing many seeds that are part of the Marquesan imperial pigeon's food supply were common.

Marquesan imperial pigeons are frugivorous birds and act as seed dispersal agents for those trees from which they feed and roost. Habitat loss, predation, or any other factor resulting in the decline of pigeons indirectly contributes to a decrease in seed dispersal, possibly contributing to low recruitment of the vital native tree species. Therefore, hunting may also contribute to the destruction and modification of habitat (See also Factor B).

The habitat in the Vaiviki Valley on the island of Ua Huka, where the pigeon was reintroduced, was classified as a protected area in 1997 (Thorsen *et al.* 2002, p. 13). There are no indications that ongoing habitat degradation from livestock grazing is occurring in this area.

In summary, the Marquesan imperial pigeon prefers to inhabit the canopy forest layer of mature forests and relies on the fruits of these trees as a food source. This habitat on Nuku Hiva has been destroyed, and continues to be destroyed by conversion of land for agriculture and development, overgrazing, and competition with exotic plant species. The species is currently restricted to seven small sites in the most remote areas of Nuku Hiva (Villard *et al.* 2003, p. 191). An intact canopy of native species is rare; in addition, the native understory and shrub layers are absent and composed mostly of browse-resistant species (Thorsen *et al.* 2002, p. 9). Poor natural forest regeneration is evident in areas where pigeons are found (Villard *et al.* 2003, p. 193). Overgrazing by goats and competition with exotic species remain a threat to the pigeon's habitat on Nuku Hiva; any additional loss of suitable habitat is likely to have a large impact on the distribution of this species.

The Marquesan imperial pigeon does not appear to experience habitat destruction on Ua Huka, as it is classified as a protected area and there is no indication of ongoing habitat degradation from livestock grazing in this area. However, the largest population of pigeons is located on Nuka Hiva, and impacts to the suitable habitat on this island are ongoing. Therefore, we find that present or threatened destruction, modification, or curtailment of the habitat or range is a threat to the continued existence of the Marquesan imperial pigeon.

B. Overutilization for Commercial, Recreational, Scientific, or Educational Purposes

Two researchers found that hunting is the primary reason for the current restricted range of the species to remote areas of Nuku Hiva (Thorsen *et al.* 2002, p. 8; Villard *et al.* 2003, p. 193). By 1922, most of the modification of habitat by man had already occurred, yet Marquesan imperial pigeons were still abundant (Villard *et al.* 2003, p. 195). In a 1922 expedition, 82 birds were killed; Villard *et al.* (2003, p. 194) theorized that this represented a significant portion of the estimated several hundred birds present at that time. After these killings, the pigeon was reported as ''not so abundant.'' In 1944, many birds were reported on the northern coast of Nuku Hiva and hunters were known to bring back full bags of birds. In 1951, the population of pigeons appeared to be decreasing and, with the introduction of shotguns in the 1950s, the effect was amplified. During the construction of the airport from 1978 to 1979, workers were known to hunt for pigeons (Villard *et al.* 2003, pp. 193, 195). On Ua Huka, a local agreement now exists not to hunt pigeons (Thorsen *et al.* 2002, p. 13).

Bird hunting in the French Polynesia was banned in 1967; however, the law is rarely enforced and hunting still occurs (Thorsen *et al.* 2002, p. 10) on Nuku Hiva. Most Marquesan imperial pigeons that are killed are opportunistic kills by those hunting goats and pigs, but some intentionally target pigeons for sale to local inhabitants (Thorsen *et al.* 2002, p. 10). In an effort to reduce illegal hunting and engage the public in conservation of local endemic species, the Société d'Ornithologie de Polynésie (Manu), a conservation organization in French Polynesia, developed a public outreach and educational program for local schools about the importance of this species. Although this appears to have reduced illegal hunting, poaching remains a threat and has the potential to rapidly reduce to the remaining small population (BLI 2009c, unpaginated). To protect the remaining populations from hunting, an agreement by the inhabitants of Nuku Hiva to stop hunting pigeons or the appointment of a ranger to enforce current laws is needed (Thorsen *et al.* 2002, p. 11).

An adult Marquesan imperial pigeon lays only one egg per year, suggesting this species is long lived (Villard *et al.* 2003, pp. 192, 195). Populations of species that are long-lived with low fecundity rates tend to be more affected by loss of breeding adults than those species with shorter lifespans and high fecundity. Therefore, an increase in adult mortality due to illegal hunting would likely have a substantial impact on the survival of this species. Furthermore, because pigeons are frugivorous and act as seed dispersal agents for those trees from which they feed and roost, further declines in pigeons may indirectly contribute to low recruitment of the vital native tree species.

In summary, hunting was likely a major contributing factor to the current restricted range and small population of Marquesan imperial pigeon. On the island of Ua Huka, because the species is in a protected area, there is a smaller human population compared to other Marquesan islands, and since there is no information indicating hunting is a threat to this species on the island of Ua Huka, we find that overutilization is not a threat to the continued existence of the pigeon. On the island of Nuku Hiva, although hunting of pigeons is illegal, the law is not enforced and poaching remains a threat. Because this species has a clutch size of one egg, poaching would have a substantial impact on the species' continued existence. Therefore, we find that overutilization is a threat to the continued existence of Marquesan imperial pigeon on the island of Nuku Hiva.

C. Disease or Predation

Avian diseases are a concern for species with restricted ranges and small populations, especially if the species is restricted to an island. Extensive human activity in previously undisturbed or isolated areas can lead to the introduction and spread of exotic diseases, some of which (*e.g.,* West Nile virus) can negatively impact endemic bird populations (Naugle *et al.* 2004, p. 704). The introduction and transmittal of an avian disease could result in the extinction of the Marquesan imperial pigeon (Blanvillian *et al.* 2007, unpaginated). Beadell *et al.* (2006, p. 2940) found the presence of Hawaii's avian malaria in reed-warblers on Nuku Hiva; however, there is no data on the effects of this malaria on the population of pigeons on the island. Although large and stable populations of wildlife species have adapted to natural levels of disease and predation within their historic ranges, any additive mortality to the Marquesan imperial pigeon population or a decrease in its fitness due to an increase in the incidence of disease or predation could adversely impact the species' overall viability (see Factor E). However, while these potential influences remain a concern for future management of the species, we are not aware of any information currently available that specifically indicates the occurrence of disease in the Marquesan imperial pigeon. No other diseases are known to affect the pigeons. In addition, the reintroduction of the pigeons to the island of Ua Huka reduces the likelihood of diseases causing extinction of the species.

Black rats were introduced to Nuku Hiva in 1915 and are now found everywhere pigeons are located on Nuku Hiva (Villard *et al.* 2003, pp. 193, 195). Rats may prey upon the eggs and nestlings of Marquesan Imperial pigeons, even if the nests are located in the tops of trees (Thorsen *et al.* 2002, p. 10). However, due to the large size of this species, adult pigeons may be able to chase away rats from their nests (Villard *et al.* 2003, p. 195). Furthermore, Thorsen *et al.* (2002, p. 10) observed juveniles and Villard *et al.* (2003, p. 195) noted a significant proportion of young pigeons, suggesting that black rats are not affecting breeding success. Due to the potential threat of black rats, pigeons were introduced to Ua Huka where black rats were not present. As an additional measure, poison bait stations were established around the wharf area of Ua Huka to prevent introduction of black rats (Thorsen *et al.* 2002, p. 17).

Cats have also been introduced to both the islands of Nuku Hiva and Ua Huka. While predation of adult and juvenile birds by cats is possible when pigeons are forced to feed on low shrubs, such as guava, due to destruction and absence of native species (See Factor A) (Thorsen *et al.* 2002, p. 10), we are not aware of any information currently available that specifically indicates that predation by cats is a threat to the survival of this species.

In summary, while avian diseases such as avian malaria in reed-warblers was found to be present on Nuku Hiva, no avian diseases are known to affect Marquesan imperial pigeons. Although predation has been indicated as a contributing factor to the decline of the species (Thorsen *et al.* 2002, pp. 9, 10; Blanvillain *et al.* 2007, unpaginated), we did not find information to suggest that predation is currently a threat to the survival of this species. Further, while black rats are found everywhere pigeons are found on Nuku Hiva, the observation of a significant proportion of juveniles suggests that predation of pigeon eggs and nestlings by black rats on Nuku Hiva is not a significant threat to pigeons. Cats are present on both islands, and there is potential for predation when pigeons are forced to feed on low shrubs, such as guava; however, there is no information to substantiate cat predation as a threat to the species' survival. Therefore, we find that disease and predation are not contributing threats to the continued existence of the pigeon throughout its range.

D. Inadequacy of Existing Regulatory Mechanisms

The Marquesan imperial pigeon is a protected species in French Polynesia; it is classified as a Category A species under Law Number 95–257. Article 16 of this law prohibits the collection and exportation of species listed under Category A. Under Article L411–1 of the French Environmental Code, the destruction or poaching of eggs or nests, mutilation, destruction, capture or poaching, intentional disturbance, the practice of taxidermy, transport, peddling, use, possession, offer for sale, or the sale or the purchase of nondomestic species in need of conservation is prohibited. The French Environmental Code also prohibits the destruction, alteration, or degradation of habitat for these species.

Hunting of this species is believed to be one of the main reasons for the species' decline (Thorsen *et al.* 2002, p. 10; Villard *et al.* 2003, p. 195). Hunting and destruction of all species of birds in French Polynesia was prohibited by a decree enacted in 1967 (Villard *et al.* 2003, p. 193). Furthermore, although restrictions on possession of firearms in Marquesas are in place, firearms are made available through visiting boats

(Thorsen *et al.* 2002, p. 10). On Ua Huka, there is an agreement in force not to hunt pigeons (Thorsen *et al.* 2002, p. 13). Although this species is fully protected, and hunting has been banned, illegal hunting of the Marquesan Imperial pigeon still occurs (see Factor B) and remains a threat on Nuku Hiva.

The Marquesas Archipelago is designated as an Endemic Bird Area (EBA) (Manu 2009, unpaginated, BLI 2009c). EBAs are territories less than 50,000 km^2 (19,300 mi^2) where at least two bird species with restricted ranges are found together, and represent priority areas for biodiversity. Nord-Ouest de Nuku Hiva is 9,000 ha area designated as an Important Bird Area (IBA) (Manu 2009, unpaginated). Designation as an IBA constitutes recognition of the area as a critical site for conservation of birds. In addition, Nuku Hiva is designated as an Alliance for Zero Extinction (AZE) (Manu 2009, unpaginated). AZEs are considered areas that are in the most urgent need of conservation. Although Nuku Hiva and Ua Huka are designated as areas of importance to the conservation of birds, these designations only serve to identify areas of biodiversity and focus conservation efforts; there is no legal protection of these areas. There is one officially protected area on Ua Huka (Vaikivi), established in 1997, which is actively managed.

In summary, regulations exist to protect the species and its habitat. The threats that affect the species on each island are different. On the island of Ua Huka, also described under Factors A and B, destruction and modification of habitat are not known to threaten this species and illegal hunting is not occurring. This is likely because the protected area on Ua Huka is actively managed, the human population is less substantial, and there is a local agreement preventing hunting on this island. Furthermore, pigeons were reintroduced to Ua Huka due to the absence of threats to the species. Therefore, we find that the inadequacy of existing regulatory mechanisms is not applicable to Ua Huka. However, as described in Factors A and B, habitat destruction continues to threaten this species and illegal hunting continues to occur on the island of Nuku Hiva. Therefore, we find that the existing regulatory mechanisms are inadequate to ameliorate the current threats to the Marquesan imperial pigeon on the island of Nuku Hiva.

E. Other Natural or Manmade Factors Affecting the Species' Continued Existence

Introduced animal and plant species threaten the habitat and survival of the Marquesan imperial pigeon by inhibiting the growth of canopy tree species needed for nesting and roosting and creating competition for food sources.

As described under Factor A, the introduction of livestock, including cattle, horses, goats and pigs, has caused and continues to cause substantial changes in the forest composition, affecting the amount of suitable habitat available for pigeons. Horses are now under control and cattle were eradicated by hunters (Thorsen *et al.* 2002, p. 9; Villard *et al.* 2003, p. 193). However, goats, in particular, overgraze native species to a level at which seedlings are consumed before they mature to a height out of goats' reach (Sykes 1969, p. 14; Parkes 1984, pp. 95, 96, 101; Villard *et al.* 2002, p. 189). Consequently, exotic plant species such as guava are able to proliferate, preventing regeneration of natural forest (Sykes 1969, p. 15; Thorsen *et al.* 2002, p. 9). To restore native forests, measures to control feral goats are needed. Local inhabitants hunt goats and pigs (Thorsen *et al.* 2002, p. 10); however, overgrazing continues to be a problem. Fenced enclosures would exclude any livestock and allow regeneration of native species (Thorsen *et al.* 2002, p. 11). In addition, introduced rats on the island of Nuka Hiva inhibit regeneration of native trees by consuming the flowers, fruits, seeds, seedlings, leaves, buds, roots, and rhizomes (Thorsen *et al.* 2002, p. 9; Meyer and Butaud 2009, p. 1570) of native tree species, further contributing to the alteration of forest composition. Introduced species are not known to threaten pigeons on Ua Huka.

Introduced rats on Nuku Hiva may also be a source of competition for food resources that would otherwise be available to pigeons. The diet for the Marquesan imperial pigeon consists of fruits from *Ficus* spp. and guava, foliage of *S. saponaria, T. cattapa,* and *Misceltum* spp., and the flowers of *H. tiliaceus, C. manghas,* and *G. speciosa* (Blanvillain and Thorsen 2003, p. 382). Rats are known to consume the flowers, fruits, and leaves of the same tree species, including guava, *T. cattapa, Ficus* spp., and *S. saponaria* (Thorsen *et al.* 2002, p. 9). The consumption of these fruits and foliage by rats may reduce the available food supply for this frugivorous bird. Furthermore, during periods of limited fruit availability, the pigeons may also compete with the white-capped fruit pigeon (*Ptilinopus dupetitbouarsii*), a wider ranging pigeon found in French Polynesia (including Nuku Hiva and Ua Huka), for food sources (Thorsen *et al.* 2002, p. 10). Abundance of fruit is critical to the breeding success of frugivorous birds. When food resources are limited, breeding output and fledgling and adult survival may also be affected (Thorsen *et al.* 2002, p. 10). This may be especially critical to the Marquesan imperial pigeon since it is a long-lived species with low fecundity. An increase in adult mortality due to decreased food availability would likely have a substantial impact on the breeding success and, ultimately, on the survival of this species.

Island populations have a higher risk of extinction than mainland populations. Ninety percent of bird species driven to extinction were island species (as cited in Frankham 1997, p. 311). Based on genetics alone, endemic island species are predicted to have higher extinction rates than nonendemic island populations (Frankham 2007, p. 321). Small, isolated populations may experience decreased demographic viability (population birth and death rates, immigration and emigration rates, and sex ratios), increased susceptibility of extinction from stochastic environmental factors (*e.g.,* weather events, disease), and an increased threat of extinction from genetic isolation and subsequent inbreeding depression and genetic drift. As discussed above, there are two small extant populations of Marquesan imperial pigeons, one on Nuku Hiva and a reintroduced population on Ua Huka. Because the species now present on Ua Huka originated from the Nuku Hiva population, there is no genetic variation between the two populations. Furthermore, we have no indication that there is natural dispersion between the populations and, thus, no genetic interchange. The lack of genetic variation may lead to inbreeding and associated complications, including reduced fitness. Species with low fecundity, like the pigeon, are particularly vulnerable to inbreeding depression because they can withstand less decrease in survival before population growth rates are affected and they recover more slowly (Lacy 2000, p. 47). In addition, genetic threats associated with small populations will exacerbate other threats to the species and likely increase the risk of extinction of island populations (Frankham 1997, p. 321).

In summary, introduced livestock and rats are altering the native forests of Nuku Hiva on which the Marquesan imperial pigeon depends. Native tree species are unable to regenerate due to overgrazing by goats; allowing graze-resistant exotic plant species to proliferate. Through consumption of fruits, flowers, seeds, and foliage, rats contribute to the alteration of the native forest and also serve as a source of competition for food. On Nuku Hiva and Ua Huka, the white-capped fruit pigeon may also serve as a source of competition for food during periods of limited fruit availability. When food resources are limited, breeding output and fledgling and adult survival may also be affected, which may be particularly critical for a species with low fecundity.

Both pigeon populations are subject to detrimental effects typical of small island populations. Decreased demographic viability, environmental factors, and genetic isolation may lead to inbreeding depression and associated complications, including reduced fitness. Species with low fecundity are particularly vulnerable because they can withstand less decrease in survival and recover more slowly. These genetic threats will exacerbate other threats to the species and likely increase the risk of extinction. Therefore, we find that other natural or manmade factors are threats to the continued existence of the Marquesan imperial pigeon on both Nuku Hiva and Ua Huka.

Status Determination for the Marquesan Imperial Pigeon

We have carefully assessed the best available scientific and commercial information regarding the past, present, and potential future threats faced by the Marquesan Imperial Pigeon. The species is currently at risk on Nuku Hiva due to ongoing threats of habitat destruction and modification (Factor A); illegal hunting (Factor B); and competition with rats for food on Nuku Hiva, as well as demographic, genetic, and environmental stochastic events associated with the species' low population, restricted range, and low fecundity (Factor E). Furthermore, we have determined that the existing regulatory mechanisms (Factor D) are not adequate to ameliorate the current threats to the species. In addition, we have determined that Factors A, B, C, and D are not factors affecting the continued existence of the species on Ua Huka. However, we have determined that the Ua Huka population is at risk due to demographic, genetic, and environmental stochastic events associated with the species' low population, restricted range, and low fecundity (Factor E).

Section 3 of the Act defines an ''endangered species'' as ''any species which is in danger of extinction throughout all or a significant portion of its range'' and a ''threatened species'' as ''any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.''

The Marquesas imperial pigeon is restricted to two islands and has a total maximum combined population estimate of 200 (80–150 on Nuku Hiva and 50 on Ua Huka). Intact canopy on Nuku Hiva is rare due to conversion of land to agriculture, overgrazing by goats and the subsequent poor natural forest regeneration, and competition with exotic plant species, which has restricted this population to seven small sites on the island. Further loss of suitable habitat could have a large impact on this small isolated population. Furthermore, hunting of pigeons is illegal, but is not enforced. Because this species is a long-lived species with low fecundity, it is particularly vulnerable to continued illegal hunting and, on both Nuku Hiva and Ua Huka, detrimental effects typical of small island populations.

Decreased demographic viability, environmental factors, and genetic isolation may lead to inbreeding depression and reduced fitness. Species with low fecundity are particularly vulnerable because they can withstand less decrease in survival and recover more slowly. These genetic threats will exacerbate other threats to the species and likely increase the risk of extinction. Based on the magnitude of the ongoing threats to the extremely small and isolated population of Marquesan Imperial Pigeon throughout its entire range, as described above, we determine that this species is in danger of extinction throughout all of its range. Therefore, on the basis of the best available scientific and commercial information, we are listing the Marquesan Imperial Pigeon as an endangered species throughout all of its range. Because we find that the Marquesan Imperial Pigeon is endangered throughout all of its range, there is no reason to consider its status in a significant portion of its range.

VI. Slender-Billed Curlew (*Numenius tenuirostris*)

Species Description

The slender-billed curlew (*Numenius tenuirostris*) is a species of wading bird, one of the six curlews of the same genus within the family Scolopacidae. It was described from Egypt in 1871 by Vieillot (Gretton 1991, p. 1). It is medium-sized and mottled brown-grey in color. It has white underparts marked with black heart-shaped spots on the flanks. It has a decurved bill that tapers to a distinctly fine tip. It has pale, barred inner primary feathers and its secondary feathers contrast markedly with its brown-black primary feathers. Its tail is virtually unmarked, with a few dark bars on a white background (BLI 2006, p. 1).

The species is believed to breed in Northwest Siberia (though the only two confirmed cases of breeding were in 1914 and 1924). The species migrates 5,000–6,000 km (3,100–3,700 mi) towards the west-southwest across Kazakhstan, passing north of the Caspian and Black Seas through southeastern and southern Europe to its wintering grounds in the Mediterranean and Middle East (Gretton 1996, p. 6; Chandrinos 2000, p. 1; Hirschfeld 2008, p. 139; Schmidt 2009, p. 46; Boere 2010, pers. comm.).

The species has been sighted in Eastern Europe, including Russia, Kazakhstan, Ukraine, Bulgaria, Hungary, Romania, and Yugoslavia; in Southern Europe, including Albania, Greece, Italy, and Turkey; in Western Europe, including France and Spain; in North Africa, including Algeria, Morocco, and Tunisia; and in the Middle East, including Iran and Iraq (van der Have *et al.* 1998, p. 36; Chandrinos 2002, unpaginated; Gretton *et al.* 2002, pp. 335, 342; Gretton 2006, pp. 10–15; BLI 2006, p. 2; Schmidt 2009, p. 44). It has also been reported in Slovenia, Uzbekistan, Turkmenistan, Oman, Saudi Arabia, and Yemen (BLI 2006, p. 2).

During the 19th Century, the slender-billed curlew was described as the most common curlew in countries such as Spain, Sicily, Malta, Tunisia, Morocco, and Algeria; described as abundant in Romania, southeast Hungary, and Italy; and regularly recorded in France (Gretton 1991, p. 16). Flocks were reported as hundreds, sometimes thousands, strong. Its population density frequently exceeded that of two relative species: The Eurasian curlew (*Nemenius arquata*) and the whimbrel (*Numenius phaeopus*) (Chandrinos 2000, p. 1). From 1900 to the 1930s, the species was still regularly recorded, although not as abundant as in the 1800s (Gretton 1991, p. 1). By 1940, a decline in slender-billed curlew populations was apparent and the species continued to decline, although flocks of more 100 birds were recorded in Morocco as late as the 1960s and 1970s (Gretton 1996, p. 6). In 1978, a flock of 150 birds was observed in Turkey (Nankinov 1991, p. 26). In the 1970s and 1980s, about 10–15 sightings were reported annually. In the 1990s, annual records consist of sightings of 1 to 3 birds, with the exception of 19 birds sighted in Italy in 1995 and a group of up to 50 wintering along the southern coast of Iran (Baccetti *et al.* 1996, p. 53; Boere and Yurlov 1998, p. 35; BLI 2006, p. 3; Hirschfeld 2008, p. 139).

No nesting birds have been found since 1924, although in 1996 an adult slender-billed curlew in flight was reported west-north-west of Tara (Bojko and Nowak 1996, p. 79; Gretton *et al.* 2002, p. 342). Juveniles were reported in 1998 and 1999, indicating that the slender-billed curlew is still breeding somewhere (Gretton *et al.* 2002, p. 335; Schmidt 2009, p. 43). Between 1987 and 1995, 1 to 3 slender-billed curlews were regularly recorded in Merja Zergas (Morocco), the last known regular wintering site; however, it has not been recorded at this location since 1995 (van der Have *et al.* 1998, p. 36; Gretton 1996, p. 6; Chandrinos 2000, p. 2; Crockford 2009, p. 62). Most of the recent records have come from southeastern Europe in countries along the migration route (Chandrinos 2000, unpaginated). However, the last confirmed sighting of a slender-billed curlew was in 2001 in Hungary (Crockford 2009, p. 62; UNEP–AEWA 2009, unpaginated).

The most recent population estimate is fewer than 50 birds (BLI 2006, p. 3; Hirschfeld 2008, p. 139; BLI 2010, unpaginated). Surveys were conducted from 1987 through 2000 in various parts of the species' historic breeding range, which covered several thousand kilometers of habitat. No slender-billed curlews were found during these survey efforts (Gretton *et al.* 2002, p. 341; CMS update 2004, p. 2). In 2009–10 a search to find this species within the non-breeding range began; this survey involved teams of observers covering 35 countries around the Mediterranean, Middle East, and Indian subcontinent (UNEP–AEWA 2009, unpaginated). As of March 2010, no slender-billed curlews have been found, which may mean the population is below an absolute minimum to be able to recover (Boere 2010, pers. comm.).

Current breeding grounds are unknown. What is known about this species' nests and nesting habitat comes from the only two confirmed historical accounts of slender-billed curlew nests. These accounts were both in the early 1900s and are described in four papers by V.E. Ushakav that were later translated. These nests were located in a wet marsh at Krasnoperovaya, south of Tara, Siberia. The habitat was described as open marsh containing some birch (*Betula*) and marshy areas adjacent to pine (*Pinus*) forests. The nests were located in the middle of the marsh on grassy hillocks or on small dry islands (Gretton *et al.* 2002, pp. 335–336). Based on the historical habitat descriptions, breeding sites occurred in the forest-steppe zone, although it is unknown whether these sites were typical of the species; there is belief that the species may also breed in more northern areas in the southern taiga or in more southern areas in the northern parts of the steppe region (Belik 1994, pp. 37–38; Danilenko *et al.* 1996, pp. 71, 76; Boere 2010, pers. comm.). Danilenko *et al.* (1996, p. 72) provided a more general habitat description taking into consideration the historical descriptions and the marginal position of those sites described by Ushakav. This description is as follows: Open, locally wet areas with dense sedge or grass vegetation, with patches of bare ground, relief which is not flat (moderate elevations and depressions), and with adjacent shrubs or woodland patches formed mostly by deciduous trees and/or pines.

Based on the early accounts, complete clutch sizes were found to be four eggs per nest between May 11 and June 1, 1900. The young fledged in early July, and family groups of five to six birds were seen wandering around the marsh in early August. Overall, slender-billed curlews were seen in their nesting grounds in Siberia from mid-May until early August (Gretton *et al.* 2002, pp. 335–336).

During seasonal migrations and in the winter months, the species is known to be more of a habitat generalist, using a variety of habitats, including steppe grassland, saltmarsh, fishponds, brackish lagoons, saltpans, tidal mudflats, semidesert, brackish wetlands, and sandy farmland near lagoons (Gretton 1991, p. 35; Hirschfeld 2008, p. 139).

There is little information on the diet of this species. The birds at Merja Zerga (wintering ground in Morocco) have been recorded eating earthworms and tipulid larvae. Elsewhere, the species has been recorded eating other insects (grasshoppers, earwigs, and beetles), mollusks, and crustaceans (Gretton 1996, p. 7).

Conservation Status

The slender-billed curlew is classified as critically endangered by the IUCN and is listed CITES Appendix I. Species included in CITES Appendix I are the most endangered CITES-listed species. They are considered threatened with extinction, and international trade is permitted only under exceptional circumstances, which generally precludes commercial trade. The species is also listed on Annex I of the European Union (EU) Wild Bird Directive (Europa Environment 2009, unpaginated) and Appendix I of the Convention on the Conservation of Migratory Species of Wild Animals (also known as CMS or Bonn Convention), which encourages international cooperation for the conservation of species.

Summary of Factors Affecting the Slender-Billed Curlew

A. Present or Threatened Destruction, Modification, or Curtailment of Habitat or Range

Breeding Grounds

Surveys of the forest-steppe area of Novosibirsk, Siberia in 1989 revealed a considerable amount of arable land interspersed with grazing land, birch woods, and marshes (Gretton 1991, p. 35). Surveyors noted that in 1990 and 1994 there were still substantial areas of marsh at Krasnopervaya that were quite similar to that described by Ushakov, with possibly more trees being present than in the early 1900s. By 1997, the area had changed dramatically; the remaining steppe plots on the higher parts of the marshes had been converted to wheat fields and the marsh itself completely covered with young forest (Boere and Yurlov 1998, p. 37). Boere and Yurlov (1998, pp. 36–37) visited 7 of the 22 sites described by Danilenko *et al.* (1996, p. 77), based on the current understanding of what slender-billed curlews require for breeding habitat, as the best potential localities for recording breeding slender-billed curlews. Of these seven localities, they found that four were completely destroyed by human activities such as overgrazing, building of drainage/irrigation canals, and conversion into arable land. They also found that agricultural activities drained the water table in many lakes, stimulating the growth of trees on formerly wet marshes.

Threats on the breeding grounds are largely unknown due to the lack of information on this species' nesting localities. The impacts to the species from habitat modification would vary depending on which habitat types are used for nesting (Gretton 1996, p. 8). However, it should be noted that conversion to agriculture has not been limited to the later 20th Century; from 1825–1858, the area under crops more than doubled in Novosibirsk, Omsk, and Tomsk (Gretton 1991, p. 36).

Passage Areas

Passage areas are those sites along the migration route that the slender-billed curlew uses for resting and feeding.

Because of the lack of occurrence data for this species, it is difficult to assess how important certain areas are to the species and fully analyze the effects of habitat modification; however there is evidence that modification has occurred in Europe and Russia (Gretton 1991, p. 33). Coastal passages in Russia and Europe have been less modified than inland wetlands; however, these wetlands provide only a small portion of the species habitat needs as 75 percent or more of the slender-billed curlew's migration is over land (Gretton 1991, p. 34).

Gretton (1991, p. 34) noted that the conversion of the Russian steppe habitat, within northwest Kazakhstan, to arable agriculture may have significantly affected the slender-billed curlew. Within the 20th Century, central Europe experienced an immense loss of steppes and wetlands. For example, an important passage area, the Pannonian Plain, in southern Hungary and the former Yugoslavia has been almost entirely converted to arable farmland. The only natural remnants remaining are those protected by a reserve status. In Hungary, these protected areas combined comprise about 74,000 ha (182, 858 ac) but are scattered among a vast area of arable farmland. In the former Yugoslavia, the protected area equals about 6,600 ha (16,309 ac), which is only one percent of the area once comprised of steppes and wetlands (Gretton 1991, p. 34).

In the past, there have been records of slender-billed curlews from the Danube floodplain (Nankinov 1991, p. 26). The majority of marshes and floodplains along the Romanian Danube have been drained. More recent sightings have come from the Danube Delta and Dobrodja lagoons, which have remained relatively intact. In Italy, during the late 20th Century, the area of arable farmland drastically increased, and largely at the expense of steppe habitat in the south. Furthermore, low-lying areas, such as the Valli di Comacchio, in Italy have been almost entirely drained and converted to agriculture (Gretton 1991, p. 34).

Gretton (1991, p. 34) also noted that Turkish wetlands had been threatened with development in the late 20th Century. Also, some of the finest coastal wetlands in Greece have been damaged due to the creation of fish farms and expansion of agriculture (Gretton 1991, p. 34).

It is probable that the species historically used a series of traditional passage sites for rest and feeding during migration. As these sites were drained or otherwise damaged, the slender-billed curlew's migration became more difficult, forcing birds to make longer nonstop flights and possibly using suboptimal coastal sites (Gretton 1991, p. 35).

Wintering Grounds

Threats to potential wintering habitat are summarized in the 1996 version of the International Action Plan for the Slender-billed Curlew (Gretton 1996, pp. 8–9). Parts of the wintering grounds (*e.g.,* the Rharb plain of northwest Morocco) have undergone extensive drainage of wetlands. Only a few scattered lakes and marshes, such as Merja Zerga, remain (Gretton 1991, p. 35). Furthermore, in Tunisia, temporary freshwater marshes of the Metbassta region have been seriously damaged by construction of dams for flood control and the provision of water supplies. Due to the damming of several streams, it is expected that the region will dry more frequently, reducing the suitability of the sites as foraging areas (van der Have *et al.* 1998, p.37). In other parts of North Africa, other types of wetlands have been less affected, including coastal sites and inland sites, such as temporary brackish wetlands. In the Middle East, the permanent marshes in the central (Qurnah) area were reduced to 40 percent of their 1985 extent by 1992, from 1,133,000 ha to 457,000 ha (2,800,000 ac to 1,129,000 ac), with further loss expected (Gretton 1996, p. 8). Although wintering grounds have experienced habitat modification, it is not to the same extent as that of the passage areas.

In conclusion, this species annually migrates 5,000 to 6,500 km (3,100 to 4,000 mi) between its presumed breeding grounds in Siberia and the last known wintering ground in Morocco, passing though many European countries. Loss of breeding ground habitat would better explain the drastic population decline, since the species is thought to use a more specialized habitat for breeding. Belik (1994, p. 37) argued that the species may nest primarily in steppe areas. If this is the case, then the species population decline would be better explained by the extensive loss of this habitat type, particularly in Kazakhstan (Gretton 1996, p. 7). Many of the areas along the migratory route, such as steppe areas in central and eastern Europe, have experienced substantial anthropogenic impacts. Loss of passage sites may have made migration difficult for this species, especially if it is dependent on a series of traditional sites. However, since the species is thought to use a wide variety of habitats along its migratory route and in its wintering grounds, it is unlikely that habitat loss in these areas has played a substantial part in the decline of this species, especially since many other wading birds using these areas have not shown such a decline (Gretton 1996, pp. 7–8). Because Merja Zerga was the only known regular wintering site for the species, and the species has not been recorded there since 1995, the situation on wintering grounds is hard to assess. Although the loss of habitat does not fully explain the drastic reduction in this species, it certainly has contributed to the decline as a secondary factor.

There is evidence of habitat loss for the slender-billed curlew in breeding, passage, and wintering grounds, and species experts name habitat loss as a threat to this species. With a population estimated at fewer than 50 birds, any loss of habitat could have a negative impact on this species. However, the habitat loss described above is historical and there is no information on habitat currently used by the slender-billed curlew for breeding, passage, or wintering grounds or habitat modification within these areas. At this time, there is not enough information to adequately assess the current or potential future threat of habitat modification or the impacts on this species. Furthermore, other species of waders that use the same type of habitat have not undergone drastic population declines seen in the slender-billed curlew population. Therefore, we find that present or threatened destruction, modification, or curtailment of the habitat or range is not a threat to the continued existence of the slender-billed curlew throughout its range.

B. Overutilization for Commercial, Recreational, Scientific, or Educational Purposes

Being the largest waders, curlews are automatically a target for hunting, particularly as their meat is said to taste ''extremely good'' (Gretton 1991, p. 37). Large-scale hunting of waders was known to occur across most of Europe during the early 20th Century, with curlews being preferred (Gretton 1996, p. 8). Although slender-billed curlews are half the weight of Eurasian curlews, they are also subject to hunting due to the similarity in appearance. Slender-billed curlews have been seen and shot with the use of decoys for Eurasian curlews (Gretton 1991, p. 37). Because the bulk of the species' migration route is over land, it is likely to be more at risk for hunting as inland sites are more accessible to man and thus have a greater concentration of hunters (Gretton 1991, p. 40). Furthermore, this species has a reputation for being ''tame,'' in that it does not show fear of humans, and was easily targeted during a hunt (Gretton 1996, p. 8).

A significant number of slender-billed curlew specimens from the early 20th Century were from markets, notably from Hungary and Italy (Gretton 1991, pp. 37–38). Between 1962 and 1987, 17 slender-billed curlews were known to have been shot (13 of these in Italy and former Yugoslovia) (Gretton 1996, p. 9). Accurate hunting records are not available for this species. The only records of shot slender-billed curlews are those that reach museum collections; Gretton (1991, p. 37) estimates that these most likely represent a small proportion, less than one percent, of all specimens of this species shot and sold and that thousands of this species were likely shot over Italy from 1880 to 1950. In parts of North Africa, hunting pressure was strong up to at least the 1970s (Gretton 1996, p. 9). In Morocco, the slender-billed curlew has not only been hunted by locals, but also by foreign hunters via tourist agencies (Gretton 1991, p. 38). One agency is known to shoot regularly in the northern part of Merja Zerga. As late as 1980, one guide described the taking of ''a great number'' from a flock of about 500 in Morocco (Gretton 1991, p. 38).

Information strongly indicates that hunting was a significant factor in the decline of the slender-billed curlew. Furthermore, loss of habitat may have concentrated this species in remaining suitable areas making the species more vulnerable to hunting at these sites. Although hunting played a significant role in the decline of slender-billed curlews in the early 20th Century, it still poses a serious threat to the species (Gretton 1991, p. 41). Even after the species became one of the rarest birds in Europe, 15 slender-billed curlews were shot between 1962 and 1987 in 5 countries. In at least two cases, the birds were shot to obtain a scientific specimen; in the other cases, it is not known whether the birds were purposely shot, but Gretton (1991, p. 41) suggests that there is considerable interest in the species for its rarity value. Although it seems unlikely that a slender-billed curlew could be found and shot with such a low population, in 1989 a slender-billed curlew was shot at Merja Zerga in Morocco.

In countries where the slender-billed curlew is protected from hunting, but other curlews can be legally shot, the slender-billed curlew is still at risk given the similarity of appearance and the inability of hunters to distinguish between species (Gretton 1991, p. 40). Italy has the most uncontrolled hunting in Europe, although hunting pressure is also heavy and often unregulated in Turkey, Greece, the former Yugoslavia, France, Spain, and Morocco. In Albania, the economic situation is such that curlews are likely at some risk due to hunting. Although all curlew species are protected in Bulgaria, there are problems with poaching and uncontrolled foreign hunters shooting globally threatened species. Intense hunting pressure in some areas of Greece puts adjacent areas historically used by slender-billed curlew at risk from illegal encroachment by hunters. Italy has problems with uncontrolled hunting next to and within protected areas. Hunting is allowed in the northern part of Merja Zerga, and as stated above, a slender-billed curlew was shot and wounded there in 1989. Slender-billed curlews and other species of curlews are protected in Turkey, but other waders are not protected and almost all waders are liable to be shot as there is little awareness or enforcement of existing laws (Gretton 1996, pp. 10–15). Given the similarity in appearance to the Eurasian curlew, what few slender-billed curlews remain are still threatened by the continued legal and illegal hunting of curlews.

In 1975, the slender-billed curlew was listed on Appendix II of the Convention on International Trade in Endangered Species of Wild Fauna and Flora (CITES). CITES is an international agreement between governments to ensure that the international trade of CITES-listed plant and animal species does not threaten species' survival in the wild. There are currently 175 CITES Parties (member countries or signatories to the Convention). Under this treaty, CITES Parties regulate the import, export, and reexport of CITES-protected plants and animal species (also see Factor D). Trade must be authorized through a system of permits and certificates that are provided by the designated CITES Scientific and Management Authorities of each CITES Party (CITES 2010a, unpaginated).

In 1983, the slender-billed curlew was uplisted to Appendix I of CITES. An Appendix-I listing includes species threatened with extinction whose trade is permitted only under exceptional circumstances, which generally precludes commercial trade. The import of an Appendix-I species requires the issuance of both an import and export permit. Import permits are issued only if findings are made that the import would be for purposes that are not detrimental to the survival of the species in the wild and that the specimen will not be used for primarily commercial purposes (CITES Article III(3)). Export permits are issued only if findings are made that the specimen was legally acquired and trade is not detrimental to the survival of the species in the wild (CITES Article III(2)).

On the same day the slender-billed curlew was listed in Appendix I, Austria entered a reservation stating that it would not be bound by the provisions of CITES relating to trade of slender-billed curlew (CITES 2010b, unpaginated). Since the species was first listed in CITES Appendix II in 1975, the only CITES trade reported to the United Nations Environment Programme—World Conservation Monitoring Center (UNEP–WCMC) occurred in 1986. Two bodies were imported into Denmark from Austria, and then reexported from Denmark to Austria, for commercial and scientific purposes (UNEP–WCMC 2010, unpaginated). In 1989, Austria withdrew its reservation (CITES 2010b, unpaginated). Based on the low numbers of slender-billed curlew reported to be in trade, with no trade reported since 1986, we believe that international trade is not a threat to the species. Furthermore, we have no information indicating that illegal trade is a threat to this species.

In summary, hunting has been indicated as a factor in the range-wide decline of this species during the first half of the 20th century. Today, both legal and illegal hunting of curlews is likely to still occur throughout the range of this species. Given the similarity in appearance with other curlew species and its rarity value, the slender-billed curlew is still at risk of hunting and based on the very small population size and the long-range migratory habits of this species, loss of individual birds is expected to have a significant impact on the remaining population. Therefore, we find that overutilization is a threat to the continued existence of the slender-billed curlew throughout its range.

C. Disease or Predation

We are unaware of any threats due to disease or predation for this subspecies. As a result, we are not considering disease or predation to be contributing threats to the continued existence of the slender-billed curlew.

D. Inadequacy of Existing Regulatory Mechanisms

As stated above, the slender-billed curlew is listed on Annex I of the European Union (EU) Wild Bird Directive, which includes protection for habitat, bans on activities that directly threaten wild birds, and a network of protected areas for wild birds found within the EU (Europa Environment 2009, unpaginated).

The slender-billed curlew is listed in Appendix I of CITES. CITES is an international treaty among 175 nations, including Albania, Algeria, Bulgaria, France, Greece, Hungary, Iran, Italy, Kazakhstan, Morocco, Oman, Romania, Russia, Saudi Arabia, Slovenia, Spain, Tunisia, Turkey, Ukraine, Yemen, and the United States, entered into force in 1975. In the United States, CITES is implemented through the U.S. Endangered Species Act of 1973, as amended. The Secretary of the Interior has delegated the Department's responsibility for CITES to the Director of the Service and established the CITES Scientific and Management Authorities to implement the treaty. Under this treaty, member countries work together to ensure that international trade in animal and plant species is not detrimental to the survival of wild populations by regulating the import, export, and reexport of CITES-listed animal and plant species. As discussed under Factor B, we do not consider international trade to be a threat impacting this species. Therefore, protection under this Treaty is an adequate regulatory mechanism.

The Wild Bird Conservation Act (WBCA) provides restrictions on the importation of slender-billed curlew into the United States. The purpose of the WBCA is to promote the conservation of exotic birds by ensuring that all imports to the United States of exotic birds is biologically sustainable and is not detrimental to the species. The WBCA generally restricts the importation of most CITES-listed live or dead exotic birds except for certain limited purposes such as zoological display or cooperative breeding programs. Import of dead specimens is allowed for scientific specimens and museum specimens. To date, no request for importation of slender-billed curlew into the United States has been received.

This species is also listed in Appendix I of the CMS or Bonn Convention, which includes species threatened with extinction. This convention encourages international cooperation for the conservation of species. Inclusion in Appendix I of CMS means that member states work toward strict protection, conserving and restoring the habitat of the species, controlling other reasons for endangerment, and mitigating obstacles to migration, whereas Appendix II encourages multistate and regional cooperation for conservation (CMS 2009, unpaginated).

A Memorandum of Understanding (MOU) was developed under CMS auspices and became effective on September 10, 1994. The MOU area covers 30 Range States in Southern and Eastern Europe, Northern Africa, and the Middle East. The MOU has been signed by 18 Range States and 3 cooperating organizations (CMS 2010, p. 17). In early 1996, a status report was produced and distributed by the CMS Secretariat. An International Action Plan for the Conservation of the Slender-billed Curlew was prepared by BLI in 1996, which was later approved by the European Commission and endorsed by the Fifth Meeting of the CMS. The Action Plan is the main tool for conservation activities for the species under the MOU. Conservation priorities include: effective legal protection for the slender-billed curlew and its look-alikes; locating its breeding grounds and key wintering and passage sites; appropriate protection and management of its habitat; and increasing the awareness of politicians in the affected countries (CMS 2009, unpaginated).

The CMS Web site (CMS 2004) includes an update on the progress being made under the Slender-billed curlew MOU. It states that conservation activities have already been undertaken or are under way in Albania, Bulgaria, Greece, Italy, Morocco, the Russian Federation, Ukraine, and Iran (CMS 2009, unpaginated). However, no details of these activities are provided.

In Algeria, Tunisia, and Turkey, the slender-billed curlew is protected (Gretton 1996, pp. 10, 14); however, we have been unable to determine under what laws it is protected or the provisions of the protection. All *Numenius* species are protected, along with most other waders, in Bulgaria under Ordinance 342, 21/4/86. The penalty for shooting a slender-billed curlew is approximately 450 U.S. dollars (USD) (Gretton 1996, p. 10). The slender-billed curlew is also protected in Greece and Hungary with penalties of 300–3,000 USD and 1,185 USD with potentially one year in jail, respectively (Gretton 1996, p. 11). In the Islamic Republic of Iran, hunting of waders is not allowed and all species of waders are protected (Behrouzi-Rad 1991, p. 33). Curlews are not listed as legal quarry species in Italy, and are thus considered protected by Gretton (1996, p. 12). All curlew species are protected in Morocco; however, other species of waders are not (Gretton 1996, p. 13).

Based on the lack of information available on this species (location of breeding and wintering areas), it is difficult to assess the adequacy of existing regulatory mechanisms in preventing the extinction of this species. Although progress is under way in various countries to better protect the habitat, prevent loss of individuals from hunting and misidentification, and educate the public about the precarious status of this species, not all 30 Range States of this species have signed the MOU (CMS 2009, unpaginated). Furthermore, many of the range countries have provisions in place to protect the slender-billed curlew; however, legal and illegal hunting continues to be a threat to the species (See Factor B). In countries where the slender-billed curlew is protected from hunting, but other curlews can be legally shot, the slender-billed curlew is still at risk given the similarity of appearance and the inability of hunters to distinguish between species (Gretton 1991, p. 40). In addition, enforcement of existing laws is also a problem in many countries (See Factor B). Therefore, we find that the inadequacy of existing regulatory mechanisms is a threat to the continued existence of the slender-billed curlew throughout its range.

E. Other Natural or Manmade Factors Affecting the Species' Continued Existence

The status of the slender-billed curlew is extremely precarious. As stated above, the most recent population estimate for this species is fewer than 50 birds. Most sightings of this species in the 1990s were of groups consisting of no more than three birds, and the last confirmed sighting of a slender-billed curlew was of a single bird in 2001. Small, isolated populations may experience decreased demographic viability (population birth and death rates, immigration and emigration rates, and sex ratios), increased susceptibility of extinction from stochastic environmental factors (*e.g.,* weather events, disease), and an increased threat of extinction from genetic isolation and subsequent inbreeding depression and genetic drift. In smaller populations, additional threats to persistence and stability often surface, which can further lead to instability of population dynamics. Among these factors are rates of mate acquisition, breeding success, transmission of genetic material, dispersal, survival, and sex determination. Further, fluctuations in rates can couple with reduction in growth rates to act synergistically (Lacy 2000, pp. 39–40).

Due to the distance of annual migration, the geographic spread of the range, and the limited numbers of birds, the slender-billed curlew is likely vulnerable to one or more threats associated with small population size. Early records of this species often referred to large flocks on migration and in winter. Based on what we know of other similar migratory bird species, it is likely that the experience of older birds was important in guiding such flocks along the migration route. As slender-billed curlew numbers declined, individuals would be more likely to join flocks of other species, notably the Eurasian curlew. The chances of slender-billed curlews meeting each other on the breeding grounds would become increasingly low (as was described for the Eskimo curlew by Bodsworth in 1954). The smaller the population, the less likely it is that this species would be able to locate another slender-billed curlew and successfully reproduce. Since this species has not been recorded on the only known historic breeding grounds for a number of years (Gretton 1996, p. 6), it is difficult to assess whether a breakdown of social behavior patterns has already occurred.

Migrant waterbirds are particularly vulnerable to climate change due to their reliance on a network of dispersed sites between which they must travel. Wetlands are one of the habitats likely to be most affected by climate change. Additionally, timing of migration between sites is extremely important as they must arrive at certain sites in time to benefit from resource abundance (Maclean *et al.* 2008, p. 22). Migration routes could also be affected by the amount and location of suitable habitat. The slender-billed curlew was found by Maclean *et al.* (2008, p. 57) to be critically threatened by climate change, after factoring in population size, range size, fragmentation, habitat, and food requirements.

It is predicted that the annual mean temperatures in Asia Minor (Turkey and Albania), the Middle East, and Europe will increase more than the global mean (Maclean *et al.* 2008, pp. 15–16). Within Asia Minor and the Middle East, temperature increases are predicted to be greater during the summer than winter and greater inland than coastal areas. Changes are predicted to be between 2–7 degree Celsius (°C) (3.6–12.6 degrees Fahrenheit (°F)), depending on the season and area. Asia Minor is predicted to experience significant decreases in rainfall, with a 20–30 percent decrease in summer and a 15–25 percent decrease in the winter. The northern Middle East is predicted to experience 30–50 percent reductions during the summer, but no major change during the winter. The southern Arabian Peninsula is predicted to be wetter throughout the year with a 5–20 percent increase in precipitation (Maclean *et al.* 2008, pp. 16, 18).

The warming in northern Europe is likely to be highest in winter with an increase of almost 10 °C (18 °F). In the Mediterranean, the warming is predicted to be highest in summer with a predicted increase of 5 °C (9 °F). Annual rainfall is likely to increase in most of northern Europe, but decrease in most of the Mediterranean area. In general, increases will be more pronounced in winter, whereas decreases will be more pronounced in summer. By 2100, southern Spain and Greece are expected to experience decreases in rainfall of 15–30 percent (Maclean *et al.* 2008, pp. 16, 18).

All of Africa is expected to be warmer this century and the annual average warming throughout the continent higher than the global average. By 2065, coastal Africa temperature is expected to increase by 1.5–3 °C (2.7–5.4 °F). Rainfall is predicted to decrease, with the Mediterranean coast experiencing less than half the present annual rainfall (Maclean *et al.* 2008, pp. 15, 17)

In addition to increases in temperature and fluctuations in rainfall, sea-level is projected to rise by 18 to 59 cm during the 21st Century, with an estimate of approximately 4 mm per year (Maclean *et al.* 2008, p. 19). However, it should be noted that these estimates do not incorporate uncertainty in certain factors, such as ice sheet flow. In light of these predictions associated with climate change, slender-billed curlew nesting habitat may be threatened by the expansion of agriculture into areas formally too cold for farming. Additionally, wintering habitat is likely to be threatened, to some degree, by sea-level rise, but more so by drier conditions in the Mediterranean and Black Seas areas, which may reduce the area covered by wetlands (Maclean *et al.* 2008, p. 63).

In summary, breakdown of social behavior patterns is increasingly likely to occur in addition to the general threats posed by small population size such as increased susceptibility to demographic, environmental, and genetic stochasticity, as this species' population levels decline. Because so few individuals have been found in recent years, it is difficult to assess whether the breakdown of social behavior patterns has already occurred. However, given the species' low numbers, this and other threats of small population size could already be occurring. Additionally, climate change could potentially alter slender-billed curlew habitat such that it negatively impacts the species. Although data on habitat currently used by slender-billed curlews is lacking, based on historical occurrence records nesting areas could be further threatened by agriculture expansion, and the amount of essential wetlands along passage and wintering areas could be significantly decreased. Therefore, we find that natural and manmade factors are threats to the continued existence of the slender-billed curlew throughout its range.

Status Determination for the Slender-Billed Curlew

We have carefully assessed the best available scientific and commercial information regarding the past, present, and potential future threats faced by the slender-billed curlew. The species is currently at risk throughout all of its range due to ongoing threats of overutilization for commercial, recreational, scientific, or educational purposes in the form of hunting (Factor B) and threats associated with small population size (Factor E). Furthermore, we have determined that the existing regulatory mechanisms (Factor D) are not adequate to ameliorate the threat of hunting to the species.

Section 3 of the Act defines an ''endangered species'' as ''any species which is in danger of extinction throughout all or a significant portion of its range'' and a ''threatened species'' as ''any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.''

The status of the slender-billed curlew is difficult to assess; species records and threats to the species are largely historical, the species has not been recorded since 2001, and recent studies have concentrated on locating the species rather than current threats to the species. However, total population for slender-billed curlew is estimated at fewer than 50 individuals. With a population of this size, the population may be below an absolute minimum to be able to recover, and genetic impacts and a breakdown of social behaviors will naturally occur, putting the species at a higher risk of extinction. Furthermore, the slender-billed curlew is at risk of being hunted either for its rarity value or due to the inability of hunters to distinguish between curlew species. Any loss of individuals from the remaining population would have a significant effect on the species' ability to recover. At this time, regulatory mechanisms, although in place, appear to be inadequate as the slender-billed curlew is still threatened with legal and illegal hunting. Based on the magnitude of the ongoing threats to the extremely small population of slender-billed curlew throughout its entire range, as described above, we determine that this species is in danger of extinction throughout all of its range. Therefore, on the basis of the best available scientific and commercial information, we are listing the slender-billed curlew as an endangered species throughout all of its range. Because we find that the slender-billed curlew is endangered throughout all of its range, there is no reason to consider its status in a significant portion of its range.

Available Conservation Measures

Conservation measures provided to species listed as endangered or threatened under the Act include recognition, requirements for Federal protection, and prohibitions against certain practices. Recognition through listing results in public awareness, and encourages and results in conservation actions by Federal and foreign governments, private agencies and interest groups, and individuals.

Section 7(a) of the Act, as amended, and as implemented by regulations at 50 CFR part 402, requires Federal agencies to evaluate their actions within the United States or on the high seas with respect to any species that is proposed or listed as endangered or threatened, and with respect to its critical habitat, if any is being designated. However, given that the Cantabrian capercaillie, Marquesan imperial pigeon, Eiao Marquesas reed-warbler, greater adjutant, Jerdon's courser, and slender-billed curlew are not native to the United States, we are not proposing critical habitat for these species under section 4 of the Act.

Section 8(a) of the Act allows limited financial assistance for the development and management of programs that the Secretary of the Interior determines to be necessary or useful for the conservation of endangered and threatened species in foreign countries. Sections 8(b) and 8(c) of the Act authorize the Secretary to encourage conservation programs for foreign endangered species and to provide assistance for such programs in the form of personnel and the training of personnel.

The Act and its implementing regulations set forth a series of general prohibitions and exceptions that apply to all endangered and threatened wildlife. As such, these prohibitions are applicable to the Cantabrian capercaillie, Marquesan imperial pigeon, Eiao Marquesas reed-warbler, greater adjutant, Jerdon's courser, and slender-billed curlew. These prohibitions, under 50 CFR 17.21, make it illegal for any person subject to the jurisdiction of the United States to "take" (take includes harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, collect, or to attempt any of these) within the United States or upon the high seas, import or export, deliver, receive, carry, transport, or ship in interstate or foreign commerce in the course of a commercial activity, or to sell or offer for sale in interstate or foreign commerce, any endangered wildlife species. It also is illegal to possess, sell, deliver, carry, transport, or ship any such wildlife that has been taken in violation of the Act. Certain exceptions apply to agents of the Service and State conservation agencies.

We may issue permits to carry out otherwise prohibited activities involving endangered and threatened wildlife species under certain circumstances. Regulations governing permits are codified at 50 CFR 17.22, for endangered species, and 17.32 for threatened species. With regard to endangered wildlife, a permit may be issued for the following purposes: for scientific purposes, to enhance the propagation or survival of the species, and for incidental take in connection with otherwise lawful activities.

Required Determinations

National Environmental Policy Act (NEPA)

We have determined that environmental assessments and environmental impact statements, as defined under the authority of the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), need not be prepared in connection with regulations adopted under section 4(a) of the Act. We published a notice outlining our reasons for this determination in the **Federal Register** on October 25, 1983 (48 FR 49244).

References Cited

A complete list of all references cited in this final rule is available on the Internet at *http://www.regulations.gov* at Docket No. FWS–R9–ES–2009–0084 or upon request from the Endangered Species Program, U.S. Fish and Wildlife Service (see the **FOR FURTHER INFORMATION CONTACT** section).

Author

The primary author of this final rule is staff of the Branch of Foreign Species, Endangered Species Program, U.S. Fish and Wildlife Service, 4401 N. Fairfax Drive, Arlington, Virginia 22203.

List of Subjects in 50 CFR Part 17

Endangered and threatened species, Exports, Imports, Reporting and recordkeeping requirements, Transportation.

Regulation Promulgation

Accordingly, we amend part 17, subchapter B of chapter I, title 50 of the Code of Federal Regulations, as set forth below:

PART 17—[AMENDED]

■ 1. The authority citation for part 17 continues to read as follows:

Authority: 16 U.S.C. 1361–1407; 16 U.S.C. 1531–1544; 16 U.S.C. 4201–4245; Pub. L. 99–625, 100 Stat. 3500; unless otherwise noted.

■ 2. Amend § 17.11(h) by adding new entries for "Adjutant, greater," "Capercaillie, Cantabrian," "Courser, Jerdon's," "Curlew, slender-billed," "Pigeon, Marquesan imperial," and "Warbler, Eiao Marquesas reed-" in alphabetical order under BIRDS to the List of Endangered and Threatened Wildlife as follows:

§ 17.11 Endangered and threatened wildlife.

* * * * *

(h) * * *

Species		Historic range	Vertebrate population where endangered or threatened	Status	When listed	Critical habitat	Special rules
Common name	Scientific name						
*	*	*	*	*	*	*	
BIRDS							
*	*	*	*	*	*	*	
Adjutant, greater	*Leptoptilos dubius* ..	....	Entire	E	783	NA	NA

Species		Historic range	Vertebrate population where endangered or threatened	Status	When listed	Critical habitat	Special rules
Common name	Scientific name						
*	*	*	*	*	*	*	
Capercaillie, Cantabrian.	*Tetrao urogallus cantabricus*.	....	Entire	E	783	NA	NA
*	*	*	*	*	*	*	
Courser, Jerdon's ...	*Rhinoptilus bitorquatus*.	India	Entire	E	783	NA	NA
*	*	*	*	*	*	*	
Curlew, slender-billed.	*Numenius tenuirostris*.	....	Entire	E	783	NA	NA
*	*	*	*	*	*	*	
Pigeon, Marquesan imperial.	*Ducula galeata*	French Polynesia ...	Entire	E	783	NA	NA
*	*	*	*	*	*	*	
Warbler, Eiao Marquesas reed-.	*Acrocephalus percernis aquilonis*.	....	Entire	E	783	NA	NA
*	*	*	*	*	*	*	

Dated: June 21, 2011.

Gregory E. Siekaniec,

Acting Director, Fish and Wildlife Service.

[FR Doc. 2011–19953 Filed 8–10–11; 8:45 am]

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Part V

Department of Agriculture

Animal and Plant Health Inspection Service

9 CFR Parts 71, 77, 78, et al.

Traceability for Livestock Moving Interstate; Proposed Rule

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

9 CFR Parts 71, 77, 78, and 90

[Docket No. APHIS–2009–0091]

RIN 0579–AD24

Traceability for Livestock Moving Interstate

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Proposed rule.

SUMMARY: We are proposing to establish minimum national official identification and documentation requirements for the traceability of livestock moving interstate. Under this proposed rule, unless specifically exempted, livestock belonging to species covered by this rulemaking that are moved interstate would have to be officially identified and accompanied by an interstate certificate of veterinary inspection or other documentation. The proposed regulations specify approved forms of official identification for each species but would allow the livestock covered under this rulemaking to be moved interstate with another form of identification, as agreed upon by animal health officials in the shipping and receiving States or Tribes. The purpose of this rulemaking is to improve our ability to trace livestock in the event that disease is found.

DATES: We will consider all comments that we receive on or before November 9, 2011.

ADDRESSES: You may submit comments by either of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov/#!documentDetail;D=APHIS-2009-0091-0001.*
- *Postal Mail/Commercial Delivery:* Send your comment to Docket No. APHIS–2009–0091, Regulatory Analysis and Development, PPD, APHIS, Station 3A–03.8, 4700 River Road Unit 118, Riverdale, MD 20737–1238.

Supporting documents and any comments we receive on this docket may be viewed at *http://www.regulations.gov/#!docketDetail;D=APHIS-2009-0091* or in our reading room, which is located in room 1141 of the USDA South Building, 14th Street and Independence Avenue, SW., Washington, DC. Normal reading room hours are 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. To be sure someone is there to help you, please call (202) 690–2817 before coming.

FOR FURTHER INFORMATION CONTACT: Mr. Neil Hammerschmidt, Program Manager, Animal Disease Traceability, VS, APHIS, 4700 River Road Unit 46, Riverdale, MD 20737–1231; (301) 734–5571.

SUPPLEMENTARY INFORMATION:

Background

Preventing and controlling animal disease is the cornerstone of protecting American animal agriculture. While ranchers and farmers work hard to protect their animals and their livelihoods, there is never a guarantee that their animals will be spared from disease. To support their efforts, the Animal and Plant Health Inspection Service (APHIS) of the U.S. Department of Agriculture (USDA) has promulgated regulations to prevent, control, and eradicate disease. Traceability does not prevent disease, but knowing where diseased and at-risk animals are, where they have been, and when, is indispensible in emergency response and in ongoing disease control and eradication programs.

We do not currently have a comprehensive animal traceability program. Some of our animal disease program regulations in 9 CFR subchapter C (''Interstate Transportation of Animals (Including Poultry) and Animal Products,'' referred to below as ''the existing regulations''), such as those for tuberculosis and brucellosis, contain components of a traceability program, *e.g.,* requirements for animals moving interstate to be officially identified and accompanied by documents recording, among other things, the animals' official identification numbers and the locations from and to which they are being moved. Such requirements, however, do not apply to all livestock or to all interstate movements. Significant gaps exist that could impair our ability to trace animals, when necessary, that may be affected with a disease. Some species, or classes of animals within a species, are subject to official identification and/or movement requirements only under the existing animal disease program regulations.

We are particularly concerned with current inadequacies in disease tracing capabilities in the cattle industry. Previously, many cattle received official identification through USDA's vaccination program for brucellosis, which requires that certain young female cattle and bison (aged 4 to 12 months) moving into and out of States or areas designated as Class B or Class C for brucellosis be vaccinated for the disease. These vaccinated calves must be permanently identified by means of a tattoo and either an official vaccination eartag or other official eartag if one is already attached to the animal (9 CFR part 78). Our eradication efforts have been tremendously successful, and now all 50 States are brucellosis-free. While this is certainly a positive development, it has resulted in a steep decline in the number of officially identified cattle. In 1988, when there were only 27 Class Free States and many more calves were subject to those requirements, 10 million calves were officially identified, but by 2010 that number had fallen to 3.1 million.

As a result of decreasing levels of official identification in cattle, the time required to conduct other disease investigations is increasing. For example, disease investigations for bovine tuberculosis frequently now exceed 150 days as USDA and State investigative teams spend substantially more time and money in conducting tracebacks. The decreased level of official identification has resulted in an expansion of the scope of investigations to identify suspect and exposed animals, necessitating the testing of thousands of cattle that would otherwise not have needed to be tested.

We have clear indications that higher levels of official identification enhance tracing capability. For example, through the National Scrapie Eradication Program (NSEP), 92 percent of the cull breeding sheep are officially identified at slaughter, primarily using flock identification eartags. This level of official identification made it possible in fiscal year 2010 to achieve traceback from slaughter of scrapie-positive sheep to the flock of origin or birth as part of the scrapie surveillance program 96 percent of the time, typically in a matter of minutes. Other diseases, in particular contagious ones, require that we trace to more than the birth premises, *i.e.,* to other premises where the animal has been after leaving the birth premises but before going to slaughter, so the scrapie model is not a complete solution for such diseases.

APHIS believes that we must improve our tracing capabilities now not only to alleviate current concerns, including the increasing number of cases of bovine tuberculosis, but also to ensure that we are well prepared to respond to new or foreign animal diseases in the future.

The traceability framework we are proposing in this rule represents a departure from our initial attempt to address the problems described above through implementation of the National Animal Identification System (NAIS). NAIS was introduced in 2004 with the long-term goal of achieving 48-hour traceability. NAIS was a voluntary system, with registration of all premises where livestock or poultry were housed or kept as the foundation of the system. Additional components of NAIS, which were expected to evolve over time, were animal identification and the recording of animal movements. In 2009, APHIS launched a series of efforts to assess the level of acceptance of NAIS, including public listening sessions in 14 cities and a review of written comments submitted by the public. Although there was some support for NAIS, the vast majority of listening session participants and commenters were highly critical of the program and of USDA's implementation efforts. Many commenters viewed the NAIS as a Government-imposed, ''one-size-fits-all'' approach to animal traceability. Producers were concerned about various issues, including having their data maintained in a Federal database and the cost of the technology that would be necessary to achieve the 48-hour traceability goal. Overall, the feedback revealed that NAIS had become a barrier to achieving meaningful animal disease traceability in the United States in partnership with America's producers.

On February 5, 2010, the Secretary announced that the Department planned to take a new approach to animal disease traceability. This new approach was developed through input from a State-Tribal-Federal working group, Tribal consultations, discussions with producers and industry, and feedback received in seven public meetings held during the spring and summer of 2010. Our overall goal is to have an adaptable approach that will help us find animals associated with a disease quickly, focus our efforts on those animals, and minimize harm to producers.

Overview of the Proposal

We are proposing to establish minimum national official identification and documentation requirements for the traceability of livestock moving interstate. These requirements are intended to improve our ability to locate animals that may be infected with or exposed to a disease. Because USDA's regulatory authority applies to interstate commerce, the requirements would not apply to movements within a State. They would also not apply to movements onto or from Tribal lands unless the movement is also an interstate movement. Additionally, in recognition of Tribal sovereignty, if a Tribe has its own system for identifying and tracing livestock, separate from those of a State, our requirements would not apply to movements entirely within that Tribal jurisdiction even if the movements cross a State line that goes through the Tribal lands. We also propose to exempt from the regulations livestock moved to a custom slaughter facility in accordance with Federal and State regulations for preparation of meat for personal consumption.

The proposed requirements would apply to cattle and bison, sheep and goats, swine, horses and other equines, captive cervids (*e.g.,* deer and elk), and poultry. The greatest gaps in identification and movement documentation requirements for traceability purposes in our current program disease regulations are for cattle. As noted above, due to the near eradication of brucellosis in cattle, the number of vaccinated heifers, which are required under the brucellosis regulations to be officially identified, has decreased, and in turn, there has been a significant decrease in the number of officially identified cattle. Therefore, our proposed regulations would contain new requirements for cattle. Because we have very limited program regulations for horses and other equines, our proposed regulations would also contain new requirements for equines. On the other hand, the traceability-related requirements in our existing program regulations for swine, sheep and goats, captive cervids, and commercial poultry are more comprehensive and, we believe, largely sufficient at this time. While we are proposing to cover those animals in this proposal, we have chosen, in most cases, to refer the reader to the identification and documentation requirements in those existing program regulations. Our proposal, however, would establish traceability requirements for poultry moved interstate to live bird markets.

Our proposed traceability requirements would have two main elements.

First, animals moved interstate would have to be officially identified. The methods and devices for identifying animals would vary by species, and within a species there may be multiple choices. For certain species, for example cattle and bison and sheep and goats, this would typically involve attaching an eartag with a unique official identification number to the animal. In some cases, most commonly with poultry and swine, animals that move through the production chain are identified as a group rather than by means of an individual eartag or other identifier being attached to each animal.

The methods, devices, and numbering systems that we propose to recognize as official identification are those that would provide for effective traceability and that can be used nationwide. All States and Tribal jurisdictions would be required to accept all official identification methods proposed for each species. An example for cattle would be an eartag with a national uniform eartagging system (NUES) number. We recognize, however, that different identification methods may exist or evolve in specific parts of the country and that there may be situations where other forms of identification may be effective and preferred by producers. Therefore, we are proposing to allow such identification to be used in lieu of official identification for livestock moved interstate when both the shipping and receiving States or Tribes agree to its use. Additionally, because we recognize that there will be logistical challenges associated with officially identifying a significantly higher number of cattle for interstate movement, we plan to phase in the requirements for identification of cattle and bison over time.

Second, animals moved interstate must be accompanied by an interstate certificate of veterinary inspection, also referred to as an ICVI. The ICVI would be issued by an accredited veterinarian (one authorized to perform work on behalf of the APHIS) or a Federal, State, or Tribal veterinarian, who would be responsible for ensuring that the animal meets applicable health requirements. The ICVI would, for certain classes of animals, show the official identification number of the animal. It would also contain information about where the animal is moving from and its destination.

We are proposing some exceptions to the requirements for an ICVI. For example, for cattle moving interstate directly to slaughter, we propose to allow use of an owner-shipper statement, rather than an ICVI. Additionally, we are proposing to allow alternatives to the ICVI for livestock moved interstate when both the shipping and receiving States or Tribes agree. We are also proposing some exceptions to the requirement for recording animal identification numbers on ICVIs (*e.g.,* for steers and spayed heifers).

These proposed identification and movement documentation requirements are the foundation for a successful traceability program.

We are also proposing some associated recordkeeping requirements. All of the specific requirements and exceptions we are proposing are explained in detail below in a section-by-section discussion of the proposed rule.

The purpose of the requirements we are proposing is to improve our ability to trace livestock in the event that disease is found. It is important to point out, though, that we do not prescribe methods or systems that States and Tribes must use in order to trace animals that have moved interstate. We expect that States (and interested Tribes) will set up systems to allow effective tracing of animals that have moved into or from their jurisdictions.

To enable us to evaluate the effectiveness of those systems, we anticipate that we will eventually establish traceability performance standards against which we could measure a State or Tribe's ability to trace covered livestock moved interstate. Later in this preamble, under the respective headings ''Performance Standards for Traceability'' and ''Traceability Evaluations of States and Tribes,'' we discuss our current thinking regarding performance standards for measuring a State's or Tribe's ability to trace covered livestock moved interstate and the potential actions that could be taken when a State or Tribe fails to meet the standards for a particular species. We are not proposing any regulatory requirements pertaining to those issues at this time; any such requirements would be established through a future, separate rulemaking. At this time, however, we would welcome public comment on our current thinking regarding the traceability performance standards.

To facilitate the implementation of our new animal traceability approach, APHIS intends to consult with an advisory group featuring representation from APHIS, States, Tribes, and industry before we make a decision. The advisory group could offer advice and recommendations on our phase-in of official identification requirements for cattle and bison (discussed in more detail below) before we make a decision, as well as provide feedback on the effectiveness of various elements of the traceability program.

Definitions (§ 90.1)

Our proposed animal traceability requirements would be contained in a new 9 CFR part 90. The proposed regulations would include a number of new definitions pertaining to animal traceability. In addition, some definitions from the existing regulations would be incorporated into proposed part 90, in some cases as they are and in others, in modified form. Most of these proposed definitions are discussed below, by category (identification, documentation, movement, and miscellaneous). In a few cases, however, proposed definitions are discussed later in this preamble as the terms are used, in order to provide needed context.

Definitions Pertaining to Official Identification

Official eartags are used for official identification of a number of species under the existing regulations and would continue to be under these proposed traceability regulations. The existing interstate movement and animal disease program regulations define *official eartag* in a number of places. We propose to define *official eartag* in part 90 as an identification tag approved by APHIS that bears an official identification number for individual animals. The proposed definition further states that, beginning 1 year after the effective date of the final rule for this proposed rule, all official eartags applied to animals must bear the U.S. shield. The design, size, shape, color, and other characteristics of the *official eartag* would depend on the needs of the users, subject to the approval of the Administrator. The official eartag would have to be tamper-resistant and have a high retention rate in the animal. This proposed definition of *official eartag* is similar to the one used in § 71.1 and elsewhere in the existing regulations. The current definition in § 71.1, however, requires that the U.S. shield be used only on eartags bearing an animal identification number (AIN) with an 840 prefix. We are proposing to broaden the U.S. shield requirement to all *official eartags* to achieve greater standardization of this type of official identification device. The delay in the effective date of the U.S. shield requirement is intended to ease the transition and allow producers time to run through existing stocks of eartags.

We propose to define *officially identified* as identified by means of an official identification device or method approved by the Administrator. The proposed definition is similar to the definition of *officially identified* in 9 CFR 77.2 but is intended to provide a more uniform definition that could eventually be applied throughout the existing regulations as well.

Further, we propose to define *official identification device or method* as a means approved by the Administrator of applying an official identification number to an animal of a specific species or associating an official identification number with an animal or group of animals of a specific species. This proposed definition is adapted from the existing one in § 71.1, where *official identification device or method* is defined as a means of officially identifying an animal or group of animals using devices or methods approved by the Administrator, including, but not limited to, official tags, tattoos, and registered brands when accompanied by a certificate of inspection from a recognized brand inspection authority. Our proposed definition of *official identification device or method* is intended to establish minimum, uniform national requirements and does not include a list of examples, since not all the devices or methods listed under the existing definition in § 71.1 would be accepted as official for all species under these proposed regulations. (Official identification devices and methods would be listed by species under proposed § 90.4 of these regulations.) For cattle and bison, for example, for reasons discussed in greater detail below, the only identification device we would recognize as official would be official eartags. However, these proposed regulations would allow brands and other methods that are not included in the proposed definition of *official identification device or method* to be used in lieu of official identification when agreed to by the shipping and receiving States and Tribes. The use of brands and other identification methods in lieu of official identification is discussed in more detail later in this document. Finally, for the sake of consistency, *i.e.,* to eliminate any possible conflict between our proposed traceability regulations and the existing ones, we would also amend the definition of *official identification device or method* in § 71.1 and in the tuberculosis and brucellosis regulations, as discussed below, to match the one we are proposing here.

As stated above, the intended use of an official identification device or method is to apply an official identification number to an individual animal or to associate such a number with a group of animals. We propose to define *official identification number* as a nationally unique number permanently associated with an animal or group of animals. The official identification number would have to adhere to one of the following systems, most of which are already in use:

- National Uniform Eartagging System (NUES).
- Animal identification number (AIN).
- Location-based number system.
- Flock-based number system.
- Any other numbering system approved by the Administrator for the official identification of animals.

We further propose in these regulations to provide definitions of these numbering systems. Those definitions are discussed below.

NUES

The existing interstate movement regulations in 9 CFR part 71 and the animal disease regulations in parts 77, 78, 79, and 80 allow for the use of the NUES as a means of identifying individual animals in commerce. The system has been in use for many years, but the existing regulations do not define the term or specify a particular format. To allow for the use of this numbering system under these proposed animal traceability regulations and to ensure greater standardization and uniformity of the NUES, we are proposing to add a definition of the term to the new animal traceability part. We would define *National Uniform Eartagging System (NUES*) as a numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal. Formatting requirements for the NUES (and other numbering systems) would be set out in our Animal Disease Traceability General Standards Document, which we would make available on the Internet at *http://www.aphis.usda.gov/traceability.*

AIN

We propose to include in part 90 a definition of *animal identification number (AIN*), which we would adapt from the existing definition of the term in 9 CFR 71.1. We propose to define the AIN, as we do in § 71.1, as a numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal. Under the proposed definition, the AIN would consist of 15 digits, with the first 3 being the country code (840 for the United States), except that the alpha characters USA or the numeric code assigned to the manufacturer of the identification device by the International Committee on Animal Recording could be used as alternatives to the 840 prefix until 1 year after the effective date of the final rule for this proposal. The existing definition lists the same formatting requirements but does not specify a sunset date for the use of AINs beginning with the characters USA or the manufacturer's code. We are proposing to phase out those two AIN formats in order to achieve greater standardization of this numbering system, while providing producers with adequate notice of the change and so they can work through existing inventories of eartags. This proposed requirement would apply only to animals tagged 1 year or more after the effective date of the final rule for this proposal; producers would not have to retag animals that had been officially identified using the USA or manufacturer's code AIN prior to that date. As is now the case, the AIN beginning with the 840 prefix would be recognized for use only on animals born in the United States. Also, like the existing definition of the AIN, the proposed definition does not require producers to use the AIN; we would continue to recognize other numbering systems as official for the identification of individual animals.

Location Identifiers

The existing regulations, *e.g.,* in parts 77 and 78, allow for the use of premises-based numbering systems on official eartags. Such numbering systems combine an official premises identification number (PIN), discussed below, with a producer's livestock production numbering system to provide a unique identification number. Numbering systems using a PIN and a producer's production numbering system would continue to be allowed under this proposed rule, but we would expand the range of allowable location identifiers. In keeping with our goal of letting States and Tribes develop traceability systems that work best for them, we would allow them to determine, according to their needs, the location to which animals moving from their jurisdictions would have to be associated. The proposed traceability regulations, therefore, do not refer to premises-based numbering systems but instead include a definition of *location-based numbering system.* Under this proposed definition, a location-based numbering system could combine either a State- or Tribal-issued location identification number (LID number) or a PIN with a producer's unique livestock production numbering system to provide a nationally and herd-unique identification number for an animal.

We propose to define *location identification (LID) number* as a nationally unique number issued by a State, Tribal, and/or Federal animal health authority to a location, as determined by the State or Tribe in which it is issued. As proposed, the LID number could be used in conjunction with a producer's own livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It could also be used as a component of a group/lot identification number (GIN), which is described below. Formatting requirements for the LID would be contained in our Animal Disease Traceability General Standards Document.

Since the PIN could be used as a component of a location-based numbering system, we are including a definition of *premises identification number (PIN)* in this proposed rule. We propose to define the PIN as a nationally unique number assigned by a State, Tribal, and/or Federal animal health authority to a premises that is, in the judgment of the State, Tribal, and/or Federal animal health authority a geographically distinct location from other premises. The PIN could be used in conjunction with a producer's own livestock production numbering system to provide a nationally and herd-unique identification number for an animal. It could be used as a component of a group/lot identification number (GIN), which is discussed below. The proposed definition of the PIN is similar to that used elsewhere in the existing regulations but would not include number and letter formatting requirements (*e.g.,* the State's two-letter postal abbreviation followed by the premises' assigned number, as is currently the case). The formatting requirements for the PIN would be contained in the Animal Disease Traceability General Standards Document.

GIN

The GIN, referred to above, provides a means of identifying groups of animals when individual animal identification is not required. Existing regulations allow for the identification of groups of animals of some species under certain conditions. The regulations in 9 CFR 71.19, which contain identification requirements for swine moving in interstate commerce, offer one such example. Adapting an existing definition of the GIN in § 71.1, we propose to define *group/lot identification number (GIN*) in this proposed rule as the identification number used to uniquely identify a ''unit of animals'' of the same species that is managed together as one group throughout the preharvest production chain. The proposed definition also specifies that when a GIN is used, it must be recorded on documents accompanying the animals; it would not, however, be necessary to have the GIN attached to each animal. This last provision is a new one, not present in the current definition in § 71.1, and is in keeping with the purpose of allowing animals of certain species to be identified by group or lot rather than individually. Additionally, while the definition of the GIN in § 71.1 includes detailed formatting requirements, we propose to remove them from the regulations and place them in the Animal Disease Traceability General Standards Document, as we are proposing to do with the requirements for the PIN.

FIN

At this time, the NSEP furnishes eartags to sheep and goat producers that bear a number that combines a unique flock identification number (FIN) with the producer's unique livestock production number. This flock-based number represents an animal group that is associated with one or more locations. This flock-based number system serves the sheep and goat industries well in their disease control and eradication efforts. The existing regulations in part 79, however, while allowing for the use of the system on eartags for sheep and goats in the NSEP, do not define flock-based number system or FIN and do not specify a particular format to be used. Therefore, to codify current practices and help ensure uniformity and consistency in the use of flock identification numbering, we are proposing to define both these terms. We propose to define *flock identification number (FIN*) as a nationally unique number assigned by a State, Tribal, or Federal animal health authority to a group of animals that are managed as a unit on one or more premises and are under the same ownership. Formatting requirements would be listed in the Animal Disease Traceability General Standards Document. We propose to define *flock-based number system* as a numbering system combining a FIN with a producer's livestock production numbering system to provide a nationally unique identification number for an animal.

Definitions Pertaining to Documentation

Under our existing interstate movement (9 CFR part 71) and animal disease program regulations (*e.g.,* 9 CFR parts 77, 78, and 79), animals that are neither disease reactors nor exposed are generally required to be accompanied by certificates when moving interstate. The term *certificate* is defined in a number of places in those regulations. Among those definitions, however, there exists some variation according to species regarding information requirements and the use of the document. In addition, there is not a uniform requirement that certificates be issued by veterinarians. The proposed addition of the ICVI to the regulations, therefore, is intended to provide a standardized document, issued by a veterinarian, for the interstate movement of animals. We would add definitions of the ICVI to these proposed traceability regulations, as well as to part 71 and to the tuberculosis (9 CFR part 77) and brucellosis (9 CFR part 78) regulations. Further, we would amend the tuberculosis and brucellosis regulations, as discussed in detail below, so that the use of ICVIs would replace the use of certificates in parts 77 and 78. The ICVI would have to be issued by a veterinarian because, among other things, it would certify that a veterinary inspection has in fact taken place. Our requirements for veterinary accreditation are contained in 9 CFR parts 160 and 161.

We are proposing, then, to define *interstate certificate of veterinary inspection (ICVI*) as an official document issued by a Federal, State, Tribal, or accredited veterinarian at the location from which animals are shipped interstate. The proposed definition further lists the information requirements for the ICVI. The ICVI must show the species of animals covered by the ICVI; the number of animals covered; the purpose for which the animals are to be moved; the address at which the animals were loaded for interstate movement; the address to which the animals are destined; and the names of the consignor and the consignee and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined. Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States or Tribes, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison are of a class of cattle and bison exempted during the initial stage of the phase-in). For those categories of animals required to be officially identified but whose identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified. An ICVI may not be issued for any animal that is not officially identified if official identification is required.

As an alternative to typing or writing individual animal identification on an ICVI, another document may be used to provide this information, but only under the following conditions:

- The document must be a State form or APHIS form that requires individual identification of animals;
- A legible copy of the document must be stapled to the original and each copy of the ICVI;
- Each copy of the document must identify each animal to be moved with the ICVI, but any information pertaining to other animals, and any unused space on the document for recording animal identification, must be crossed out in ink; and
- The following information must be written in ink in the identification column on the original and each copy of the ICVI and must be circled or boxed, also in ink, so that no additional information can be added:
  - The name of the document; and
  - Either the unique serial number on the document or, if the document is not imprinted with a serial number, both the name of the person who prepared the document and the date the document was signed.

The information requirements for the ICVI are closely modeled upon requirements for certificates in § 78.1 of the brucellosis regulations. These proposed requirements are necessary to provide States, Tribes, and APHIS with adequate information to conduct successful traceback investigations.

In certain cases, we would allow for the use of an owner-shipper statement in lieu of an ICVI. We propose to define *owner-shipper statement* as a statement signed by the owner or shipper of the livestock being moved stating the location from which the animals are moved interstate; the destination of the animals; the number of animals covered by the statement; the species of animal covered; the name and address of the owner at the time of the movement; the name and address of the shipper; and the identification of each animal, as required by the regulations, unless the regulations specifically provide that the identification does not have to be recorded. The proposed information requirements enumerated under this definition are incorporated from existing regulations pertaining to identification of cattle for interstate movement in § 71.18.

Definitions Pertaining to Interstate Movement

Because these proposed regulations concern the movement of animals interstate, it is necessary to include a definition of *interstate movement.* We would define *interstate movement* as a movement from one State into or through any other State. This proposed definition is taken from the definition of *interstate* currently used in our tuberculosis and brucellosis regulations in 9 CFR parts 77 and 78, respectively.

We propose to define the term *move* as to carry, enter, import, mail, ship, or transport; to aid, abet, cause, or induce carrying, entering, importing, mailing, shipping, or transporting; to offer to carry, enter, import, mail, ship, or transport; to receive in order to carry, enter, import, mail, ship, or transport; or to allow any of these activities. This proposed definition is incorporated from the Animal Health Protection Act, minus a provision concerning release into the environment that is not applicable to animal traceability.

As will be discussed later in this document, movement and documentation requirements may differ in some cases, depending on whether or not an animal is moved directly to a particular destination. For that reason, it is necessary to include a definition of *directly.* We would define *directly* as without unloading en route if moved in a means of conveyance and without being commingled with other animals, or without stopping, except for stops of less than 24 hours that are needed for food, water, or rest en route if the animals are moved in any other manner. This proposed definition has been adapted from the existing one in § 78.1 but modified to allow for stops needed to care for the animals in the shipment.

Not only the nature of an animal's interstate movement (directly or otherwise) but also the destination to which it is moved may affect the requirements governing such movement. Specifically, as discussed in greater detail later in this document, we would provide exemptions from the requirement for official identification for cattle and bison moved interstate directly to an approved livestock facility or recognized slaughtering establishment. It is necessary, for the sake of clarity, to include in this proposed rule definitions of such facilities. We propose to define *approved livestock facility* as a stockyard, livestock market, buying station, concentration point, or any other premises under State or Federal veterinary inspection where livestock are assembled and that has been approved under § 71.20. This proposed definition matches the existing one in § 71.1. We propose to define *recognized slaughtering establishment* as any slaughtering facility operating under the Federal Meat Inspection Act (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (21 U.S.C. 451 *et seq.*), or State meat or poultry inspection acts. This proposed definition is based on the definitions of the term used elsewhere in the existing regulations.

Miscellaneous Definitions

As noted above in our overview section, these proposed regulations would only apply to certain species of livestock: Cattle and bison, sheep and goats, swine, horses and other equines, captive cervids, and poultry. We propose, therefore, to include in this proposed rule a new definition of *covered livestock* that would simply list those species.

Some of the proposed definitions discussed above, *e.g., approved livestock facility,* refer to livestock more generally. Species that could be present at such a facility would not necessarily be limited to those covered under this rulemaking. It is necessary, therefore, to include a definition of *livestock* in this proposed rule. We propose to define *livestock* as all farm-raised animals. This proposed definition comes from the Animal Health Protection Act (7 U.S.C. 8302).

In the overview section of this preamble, we referred to our plans to phase in official identification requirements for cattle and bison. As discussed in greater detail below, cattle and bison associated with greater risk of contracting and spreading disease would be subject to the official identification requirements before those associated with lesser risk. The former category includes sexually intact cattle and bison 18 months of age or over, dairy cattle, and cattle and bison used for rodeos, recreational events, shows, or exhibitions. While most of these designations are self-explanatory, that of dairy cattle is not. We are therefore including in this proposed rule a definition of *dairy cattle.* Under this proposed definition, all cattle, regardless of age or sex or current use, that are of a breed(s) typically used to produce milk or other dairy products for human consumption would be considered dairy cattle. We propose to define *dairy cattle* in such an inclusive manner because both male and female calves are often moved from birth premises and managed at multiple locations. The movement and commingling of dairy calves and the associated risk of disease exposure and spread warrant the official identification of all dairy animals.

General Requirements for Traceability (§ 90.2)

Under these proposed regulations, no person (a term we propose to define, using a standard definition employed elsewhere in the regulations, as any individual, corporation, company, association, firm, partnership, society, or joint stock company, or other legal entity) could move covered livestock interstate or receive such livestock moved interstate unless the livestock meet all applicable requirements of the traceability regulations. We consider these proposed requirements, which are discussed in detail later in this document, to be the minimum necessary for a successful animal traceability program.

In addition to these proposed traceability requirements, all covered livestock moving interstate would continue to be subject to existing disease control and eradication program regulations, *e.g.,* for tuberculosis, brucellosis, etc., in 9 CFR subchapter C. While this proposed rule would establish minimum traceability requirements, the disease program regulations may contain additional, or more specific, requirements necessary to control or eliminate livestock diseases. It is not our intention to loosen those disease program requirements; hence, they would be given precedence if they were to conflict in any way with the general traceability requirements being proposed here.

There are two circumstances when the traceability requirements would not apply to interstate movement of covered livestock:

- The movement occurs entirely within Tribal land that straddles a State line, and the Tribe has a separate traceability system from the States in which its lands are located; or
- The movement is to a custom slaughter facility in accordance with Federal and State regulations for preparation of meat for personal consumption.

Under this rulemaking, Tribal lands, whether entirely within a State or straddling State lines, would be covered by the same traceability system as the State or States within which they are contained, unless the Tribal representatives choose to have their own traceability system separate from the State(s). If a Tribal land straddling a State line does have a separate traceability system from the States in which it is contained, then, because of Tribal sovereignty, livestock movements taking place entirely within that Tribal land, even across State lines, would not be regarded as interstate movement under our regulations. Therefore, the proposed traceability requirements for interstate movement would not apply.

We do not deem it necessary to apply our proposed traceability requirements to interstate movement of covered livestock to a custom slaughter facility under the conditions described above.

Such animals are accurately identified so the meat products are properly provided to the owner or person responsible. Therefore, those animals are already highly traceable to the farm or other location from which the animals were moved to the slaughter facility.

Recordkeeping Requirements (§ 90.3)

As we have noted, we are proposing in these regulations to require that, with certain exceptions, covered livestock moving interstate be officially identified and accompanied by an ICVI or other movement document. This proposed rule would require that any State, Tribe, accredited veterinarian, or other person or entity who distributes official identification devices maintain for a minimum of 5 years a record of the names and addresses of anyone to whom the devices were distributed. We would also require that approved livestock facilities keep for a minimum of 5 years any ICVIs or alternate documentation used in lieu of an ICVI for covered livestock that enter the facilities. Our proposed 5-year requirement for maintaining records of official identification devices and ICVIs or other animal movement documents is necessary because certain animal diseases, such as tuberculosis and bovine spongiform encephalopathy, have very long latency or incubation periods, which can make traceback efforts quite challenging. Such diseases may not manifest themselves until an animal reaches adulthood, possibly several years after it was officially identified and/or moved interstate. The proposed recordkeeping requirements would enhance our ability to conduct traceback investigations of infected and exposed animals, even in cases where the disease that the animal has contracted or been exposed to has a very long latency period. We request comment on the burden and practical utility of this proposed requirement.

Official Identification (§ 90.4)

Official Identification Devices and Methods

We will now discuss how persons moving covered livestock interstate may comply with the proposed requirement that such livestock bear official identification. Please note that, in order to provide flexibility, the Administrator could authorize the use of additional devices or methods of identification if they would provide for effective traceability.

In this proposed rule, official identification devices or methods approved by the Administrator for use on covered livestock moving interstate are listed by species. (They would also be listed in our Animal Disease Traceability General Standards Document.) These requirements are described in detail below. Listing official identification methods by species provides clarity to livestock owners so they know what official identification options are accepted for the movement of their animals anywhere in the United States.

It is our intention that any device or method authorized by the proposed regulations as official identification for a species be accepted by any destination State or Tribe. Therefore, only those identification devices or methods that are available throughout the United States for a given species would be listed as official under the proposed regulations, and some identification practices that may be used regionally would not be listed, though we may allow them to be used in lieu of official identification.

Branding of cattle and bison is one prominent example of an identification method that would not be listed as official identification for cattle and bison under the proposed regulations but would be allowed to be employed in lieu of official identification. If we were to list brands as a means of official identification, all States would have to accept animals identified with brands into their jurisdictions. At this time, however, 36 States do not have brand inspection authorities, so brands would not be suitable for listing as a means of official identification. Yet, recognizing the value of brands and their prevalence in the western United States, the proposed rule does provide sufficient flexibility to allow for the use of brands on covered livestock moving interstate in lieu of official identification when brands are acceptable to both the shipping and receiving State or Tribe. This provision for use of alternative means of identification would apply to all other identification practices, including tattoos, breed registries, etc., that States and Tribes may elect to use instead of the official identification methods listed under these proposed regulations, provided that they are acceptable to both the shipping and receiving States or Tribes.

Official Identification Devices and Methods for Cattle and Bison

While the existing regulations recognize a number of means of identification, such as eartags, backtags, tattoos, and brands, as official for use on cattle and bison moving interstate, we are proposing to recognize eartags as the only device that may be used for the official identification of individual cattle and bison. Official eartags provide a simple means of uniquely identifying the animal. Eartags are a more permanent means of identification than backtags, which may come off the animal, and provide greater readability and ease of recording than do tattoos. In addition to individual identification of cattle and bison by means of official eartags, we propose to provide for the use of GINs when cattle and bison are eligible for interstate movement using group/lot identification. The GIN provides identification for the entire group of animals. As we have already noted, the number itself does not need to be attached to each individual animal.

Official Identification Devices and Methods for Equines

Equines would have to be identified by one of the following methods:

- A description sufficient to identify the individual equine, as determined by a State or Tribal animal health official in the State or Tribe of destination, or APHIS representative, including, but not limited to, name, age, breed, color, gender, distinctive markings, and unique and permanent forms of identification when present (*e.g.,* brands, tattoos, scars, cowlicks, or blemishes); or
- Electronic identification that complies with ISO 11784/11785 (ISO 11784 defines the code structure of the number which is embedded in the transponder's microchip. ISO 11785 defines the technical specifications of how the transceiver communicates with the transponder.); or
- Digital photographs of the equine sufficient to identify the individual equine, as determined by a State or Tribal animal health official in the State or Tribe of destination, or APHIS representative; or
- For equines being commercially transported for slaughter, a USDA backtag authorized by part 88 of this chapter.

The identification devices and methods listed above are all currently used on horses and other equine species in the United States and can provide for adequate traceability when they are moved interstate.

Official Identification Devices and Methods for Poultry

Poultry would have to be identified either by means of a GIN, or with sealed and numbered leg bands. These identification methods are consistent with those required for poultry flocks participating in the National Poultry Improvement Plan (NPIP) regulations (9

CFR parts 145 through 147), and thus would not represent a change for most poultry producers.

Official Identification Devices and Methods for Sheep and Goats

Currently, official identification devices or methods approved by the Administrator for sheep and goats required to be officially identified for interstate movement are listed in the scrapie regulations in 9 CFR 79.2.(a). These include electronic implants, official eartags, USDA backtags, official registry tattoos, premises identification eartags, and any other device or method approved by the Administrator. The process for approving official identification tags and new identification types for sheep or goats is described in § 79.2(f) and (g), respectively. This proposed rule would not change any of those requirements. We would simply refer the reader to part 79.

Official Identification Devices and Methods for Swine

Currently, official identification devices or methods approved by the Administrator for swine needing to be officially identified for interstate movement are listed in § 71.19. These include official eartags, USDA backtags, official swine tattoos and other tattoos, ear notching, and any other device or method approved by the Administrator. As is the case for sheep and goats, this proposed rule would not change those requirements, since, in our view, they already provide for adequate traceability. We would refer the reader to § 71.19.

Official Identification Devices and Methods for Captive Cervids

Interstate movement requirements for captive cervids are currently included in the tuberculosis regulations in part 77. Except for captive cervids from accredited-free States or zones, all captive cervids moving interstate are required under part 77 to be officially identified. As discussed in detail below, we are proposing in this document to amend part 77 to align the requirements in that part with our proposed traceability requirements. To avoid redundancy, this proposed rule would simply state that captive cervids that are required to be officially identified under these proposed regulations for interstate movement must be identified by a device or method authorized by part 77. It should be noted that captive cervids moved interstate from an accredited-free State or zone would not be exempted from official identification requirements under the traceability regulations. As discussed further below, we would also amend part 77 to indicate that such captive cervids would be subject to the traceability requirements and thus not exempted from the requirement that they be officially identified in order to move interstate.

Official Identification Requirements for Interstate Movement

In the paragraphs that follow, we discuss proposed requirements for each species of covered livestock pertaining to aspects of official identification other than the devices or methods themselves. Included in this section are requirements for when covered livestock must be officially identified for interstate movement and, in some cases, other administrative requirements pertaining to official identification.

When Cattle and Bison Must Be Officially Identified

With certain exceptions, cattle and bison moved interstate would have to be officially identified prior to the interstate movement using one of the official identification devices or methods previously discussed. These exceptions, which include the use, in lieu of official identification, of devices or methods agreed to by the shipping and receiving States or Tribes, are discussed in detail in the paragraphs that follow.

An exception would be made for cattle and bison moving interstate as part of a commuter herd with a copy of the commuter herd agreement. In this proposed rule, we define *commuter herd* as a herd of cattle or bison moved interstate during the course of normal livestock management operations and without change of ownership directly between two premises, as provided in a commuter herd agreement. We propose to define *commuter herd agreement* as a written agreement between the owner(s) of a herd of cattle or bison and the animal health officials for the States and/or Tribes of origin and destination specifying the conditions required for the interstate movement from one premises to another in the course of normal livestock management operations and specifying the time period, up to 1 year, that the agreement is effective. A commuter herd agreement would be subject to annual renewal. Meeting commuter-herd requirements in lieu of official identification requirements would still provide adequate traceability in our view.

We would also provide an exception from the requirement for official identification prior to interstate movement for cattle and bison moved directly from one State through another State and back to the original State. This exception would allow for movement without official identification in cases where State borders are configured such that a truck containing cattle or bison would pass through a second State when moving the animals to a second location within the State of origin. An example of this type of movement would be a shipment of cattle originating at a location in Texas and passing through Oklahoma territory en route to a second location in Texas. Because the animals would not exit the truck en route and therefore would not be commingled with other animals, we do not view official identification of the individual animals in the shipment as necessary.

Cattle and bison would also be allowed to move interstate without being officially identified prior to the movement if the interstate movement is directly to an approved tagging site, provided that the cattle and bison are officially identified there before they are commingled with cattle and bison from other premises. In this proposed rule, we define *approved tagging site* as a premises, authorized by APHIS or State or Tribal animal health officials, where livestock can be officially identified on behalf of their owner or the person in possession, care, or control of the animals when they are brought to the premises. Such sites would afford producers a safe and convenient alternative, not provided for in the existing regulations, to identifying their animals themselves. This proposed exception is intended to allow producers to take advantage of this alternative when they are unable to tag animals at their farm or ranch.

As discussed earlier, we would also allow cattle and bison to move interstate without using one of the types of official identification specifically approved for that purpose under these proposed regulations by the Administrator if the cattle and bison are moved between shipping and receiving States or Tribes with another form of identification, including but not limited to brands, tattoos, and breed registry certificates, as agreed upon by animal health officials in the shipping and receiving States or Tribes. In such situations, the shipping and receiving States or Tribes would determine whether that other form of identification is sufficient to enable the States or Tribes to meet their own traceability needs. This exemption is in keeping with our goal of allowing sufficient flexibility for States and Tribes to employ the traceability options that work best for them. If Tribal land straddles a State line and the Tribe does not have a separate traceability system from the States in which it is contained, animal movements within the Tribal land that cross the State border would be considered interstate movements under this proposed rule. In such cases, the cattle and bison could still be moved across the State border using a form of identification agreed upon by animal health officials in the States of origin and destination.

As described in greater detail below, we plan to phase in our official identification requirements for cattle and bison, applying them immediately upon the effective date of the final rule for this proposed rule to certain classes of cattle and bison and over time to other classes of cattle and bison. Until the date on which the official identification requirements apply to all cattle and bison, cattle and bison would also be eligible for interstate movement without official identification if they are moved directly to a recognized slaughtering establishment or directly to no more than one approved livestock facility approved to handle ''for slaughter only'' animals (cattle or bison that, when marketed, are presented/sold for slaughter only) and then directly to a recognized slaughtering establishment; and

- They are moved interstate with a USDA-approved backtag; or
- A USDA-approved backtag is applied to the cattle or bison at the recognized slaughtering establishment or federally approved livestock facility approved to handle ''for slaughter only'' animals.

Because backtags are not considered to be a permanent form of identification, we are proposing to discontinue allowing the use of USDA backtags as official identification for cattle and bison. We would, however, allow their use in lieu of official identification for animals going to slaughter. We therefore propose to define *United States Department of Agriculture (USDA) approved backtag* as a backtag issued by APHIS that provides a temporary unique identification for each animal. The inclusion of the word temporary is what distinguishes this proposed definition from the otherwise identical definition of *United States Department of Agriculture (USDA) backtag* in § 71.1.

The phase-in of the proposed official identification requirements for cattle and bison would proceed as described in the paragraphs that follow. Beginning on the effective date of the final rule for this proposed rule, the official identification requirements would apply to all sexually intact cattle and bison 18 months of age or over, dairy cattle of any age, cattle and bison of any age used for rodeo or recreational events, and cattle and bison used for shows or exhibitions. Because cattle and bison belonging to these categories tend to have longer lifespans than feeder animals and move around more, they have more opportunities for commingling and thus present a greater risk of spreading disease via interstate movement. It is therefore necessary to prioritize traceability of these animals over feeder animals. APHIS requests comment on this determination and the decision to implement the requirements for this subgroup first.

APHIS recognizes that the second stage of the phase-in process, the expansion of the official identification requirements to all remaining classes of cattle and bison, estimated to be approximately 20 million animals annually, could disrupt the management and marketing of cattle if not implemented properly. Critical to successful implementation is to ensure that our proposed official identification requirements are being implemented effectively throughout the production chain for all cattle required to be officially identified in the initial phase. Therefore, we are proposing to conduct an assessment of the workability of the requirements for cattle in the initial phase before expanding the official identification requirements to cover all remaining classes of cattle and bison. When we are ready to begin that assessment, we will publish a notice in the **Federal Register**. The notice will describe the procedures we will use in our assessment, as well as its objectives.

The assessment will involve an advisory group with industry representation from sectors most affected by the official identification requirements. The advisory group will provide feedback on the effectiveness of various elements of the initial phase of identifying cattle and offer recommendations regarding the application of the official identification requirements to beef cattle under 18 months of age.

APHIS requests comment on our proposal to apply the official identification requirements discussed above to all remaining classes of cattle, in particular, on the costs and benefits of doing so and on any practical difficulties or unintended consequences that may result. Further, we request comment on how APHIS should conduct the assessment process described above. We are particularly interested in comments on what information APHIS should collect and the methods by which it should be collected.

We are proposing to delay implementing official identification requirements for beef cattle under 18 months of age until 70 percent of all cattle initially required to be officially identified are found to be in compliance with official identification requirements. We would evaluate a representative cross-section of the cattle population to determine whether the 70-percent compliance rate has been attained. While higher rates of compliance are ultimately expected and necessary, the 70-percent figure would represent a significant increase in the use of official eartags on adult cattle, indicating that effective tagging practices are in place. We will ask the advisory group, as part of their review of the initial phase, to consider and comment on our data and the evaluation methodology we used for determining that the 70-percent rate of compliance has been attained. As indicated above, the advisory group would also provide feedback that would aid us in making our determination that the official identification requirements were being effectively implemented during the initial phase.

Additionally, we welcome comments and suggestions from the public on factors other than compliance rate that APHIS should consider when assessing the effectiveness of the initial official identification requirements for cattle in enhancing traceability.

APHIS will consider the advisory report and all feedback from the public regarding the official identification of beef cattle under 18 months of age. When we have completed our assessment and determined that expansion of the official identification requirements for cattle is viable, APHIS will publish a notice of the availability of the assessment in the **Federal Register** and take comments from the public. If after reviewing the comments, APHIS decides to move forward with the implementation of the second stage of the phase-in process, APHIS will publish an additional notice in the **Federal Register** discussing the comments and announcing the date (1 year after the date of publication of the notice) upon which the official identification requirements will become effective for all cattle and bison.

When Sheep and Goats Must Be Officially Identified

Under this proposed rule, sheep and goats moving interstate would have to be officially identified prior to the interstate movement unless they are exempted under the scrapie regulations in part 79 from official identification requirements or are officially identified after the interstate movement, as provided in part 79.

When Swine Must Be Officially Identified

Swine moving interstate would have to be officially identified in accordance with § 71.19 of the existing regulations. Included in that section are requirements for the handling and administration of official identification devices or methods.

When Equines Must Be Officially Identified

Horses and other equines moving interstate would have to be officially identified prior to interstate movement in accordance with these proposed regulations or identified as agreed upon by State or Tribal officials in the jurisdictions involved in the movement, or, if the horses are being commercially transported to slaughter, in accordance with part 88.

When Poultry Must Be Officially Identified

The proposed requirements for poultry are similar to those for equines. Poultry moving interstate would have to be officially identified prior to interstate movement or identified as agreed upon by State or Tribal officials in the shipping and receiving jurisdictions.

When Captive Cervids Must Be Officially Identified

Captive cervids moving interstate would have to be officially identified prior to interstate movement in accordance with the tuberculosis regulations in part 77.

Use of Multiple Official Identification Devices

The use of multiple official identification devices or methods with multiple official identification numbers for a single animal has the potential to cause confusion and impede efforts to track the movements of that animal. We propose, therefore, to prohibit the use of more than one official identification device or method on an animal, beginning on the effective date of the final rule for this proposed rule, with some exceptions. Exceptions to the prohibition would be granted under the following circumstances when the use of more than one official identification device or method may be appropriate or necessary:

• A State or Tribal animal health official or an area veterinarian in charge could approve the application of a second official identification device in specific cases when the need to maintain the identity of an animal is intensified, such as for export shipments, quarantined herds, field trials, experiments, or disease surveys, but not merely for convenience in identifying animals. The person applying the second official identification device would have to record the date on which the second official identification device was added, the official number of the device already applied to the animal, and the reason for the additional official identification device or method. Those records would have to be maintained for a minimum of 5 years.

• An eartag with an animal identification number (AIN) beginning with the 840 prefix (either radio frequency identification or visual-only tag) may be applied to an animal that is already officially identified with an eartag with a NUES number, as AIN devices are commonly used for herd management purposes. The animal's official identification number on the existing official identification eartag must be recorded and reported in accordance with the AIN device distribution policies, which can be found in our Animal Disease Traceability General Standards Document.

• A brucellosis vaccination eartag with a NUES number could be applied for management purposes in accordance with the existing brucellosis regulations to an animal that is already officially identified under the traceability regulations.

Removal or Loss of Official Identification Devices

We propose to modify certain existing requirements pertaining to the removal or loss of official identification devices. The existing regulations in § 71.22 state that official identification devices are intended to provide permanent identification of livestock and to ensure the ability to find the source of animal disease outbreaks. Section 71.22 also prohibits the intentional removal of such devices except at the time of slaughter. We would incorporate that prohibition into our proposed regulations in part 90 in modified form, allowing for removal of official identification devices not only at slaughter, but also at any other location where the animal may be upon its death or as otherwise approved by the State animal health official or an area veterinarian in charge when a device needs to be replaced. This proposed change would codify existing practices.

We would provide that all man-made identification devices affixed to covered livestock moved interstate must be removed at slaughter and correlated with the carcasses through final inspection by means approved by the Food Safety and Inspection Service (FSIS). If diagnostic samples are taken, the identification devices must be packaged with the samples and be correlated with the carcasses through final inspection by means approved by FSIS. Devices collected at slaughter must be made available to APHIS and FSIS. This proposed requirement is consistent with FSIS's requirements and would enhance our ability to conduct traceback investigations in the event of a positive post-mortem diagnosis.

We would further propose that all official identification devices affixed to covered livestock carcasses moved interstate for rendering must be removed at the rendering facility and made available to APHIS. This is a new requirement that would also enhance our traceback capabilities. APHIS requests comment on the costs and benefits of this proposed requirement.

The proposed rule would not require that producers keep records of animals that are tagged on their farms, moved onto or from their farms, or die on their farms. The percentage of animals that die on farms is so small in comparison with those that are slaughtered or rendered, that the overall access to terminated animal records would not be significantly impacted negatively if those records were not made available to APHIS. Producers are encouraged to record such information, however, for general herd-management recordkeeping and, if needed, to support disease investigation activities that may include their operations,

Under this proposed rule, if an animal were to lose an official identification device and need a new one, the person applying the new one would have to record the following information about the event and maintain the record for 5 years: The date the new official identification device was added; the official identification number on the device; and the official identification number on the old device, if known. This proposed recordkeeping requirement, which is a new one, would aid State, Tribal, and Federal officials when it is necessary to trace such animals.

Replacement of Official Identification Devices

We are also proposing some new requirements pertaining to the replacement of official identification devices for reasons other than loss. Though in practice there are circumstances that might necessitate the replacement of such devices, the existing regulations are silent on the matter. To prevent any confusion regarding when official identification devices may be replaced in accordance with the regulations, it is necessary to specify those circumstances to the extent possible. We are therefore proposing to provide that a State or Tribal animal health official or an area veterinarian in charge could authorize the replacement of an official identification device under circumstances that include, but are not limited to, the following:

- Deterioration of the device such that loss of the device appears likely or the number can no longer be read;
- Infection at the site where the device is attached, necessitating application of a device at another location (*e.g.,* a slightly different location of an eartag in the ear);
- Malfunction of the electronic component of a radio frequency identification (RFID) device; or
- Incompatibility or inoperability of the electronic component of an RFID device with the management system or unacceptable functionality of the management system due to use of an RFID device.

In order to facilitate traceback, we also propose to require that records be kept when official identification devices are replaced under such circumstances. The person replacing the device would have to record the following information about the event and maintain the record for 5 years:

- The date on which the device was removed;
- Contact information for the location where the device was removed;
- The official identification number (to the extent possible) on the device removed;
- The type of device removed (*e.g.,* metal eartag, RFID eartag);
- The reason for the removal of the device;
- The new official identification number on the replacement device; and
- The type of replacement device applied.

Sale of Transfer of Official Identification Devices

The sale or transfer of official identification devices between producers may complicate efforts to trace animals. We therefore provide that official identification devices may not be sold or otherwise transferred from the premises to which they were originally issued to another premises without the authorization of the Administrator or a State or Tribal animal health official.

Documentation Requirements for Interstate Movement (§ 90.5)

Generally, under these proposed regulations, covered livestock moving interstate would have to be accompanied by an ICVI, unless the regulations allow a specific movement without an ICVI, or alternative documentation is agreed upon by the shipping and receiving States or Tribes, or another form of documentation is required for a particular species under the existing disease program regulations in 9 CFR subchapter C.

Information requirements for ICVIs have already been discussed above. We are also proposing to add new requirements for the issuance and use of ICVIs and other documents used for interstate movement of animals. The person directly responsible for animals leaving a premises would be responsible for ensuring that the animals are accompanied by the ICVI or other interstate movement document. The APHIS representative, State, or Tribal representative, or accredited veterinarian who issues an ICVI or other document required for the interstate movement of animals would have to forward a copy of the ICVI or other document to the State animal health official of the State of origin within 5 working days. The State or Tribal animal health official in the State or Tribe of origin, in turn, would have to forward a copy of the document to the State of destination within 5 working days. These proposed requirements would ensure that such documents would be issued only by qualified personnel, would accompany the animals being moved, and would be made available in a timely manner for use by APHIS and State animal health officials in traceback investigations. The proposed 5-day limit for forwarding is intended to facilitate a traceback and/or trace forward investigation if an animal moved interstate in accordance with the regulations were found to be infected. Requiring the person issuing the ICVI or other document only to forward it to the State of origin rather than the State of destination as well would lessen his or her paperwork burden.

These proposed requirements are similar to those in § 78.2 for the handling of certificates, but have been streamlined for clarity and adapted in such a way as to ensure to the greatest extent possible that the documents are received by all personnel that may need them for conducting traceback investigations. As discussed later in this document, we would amend § 78.2 so that the document handling requirements there and in these proposed traceability regulations would be consistent.

It should be noted that the proposed timeframes and forwarding requirements are based on the handling of paper documents. As is now the practice generally when APHIS or State veterinarians issue veterinary certificates, if ICVIs or other documents were to be issued electronically, they would be transmitted simultaneously to both the State of origin and the State of destination.

We are proposing certain exemptions to the requirement that cattle and bison moving interstate must be accompanied by an ICVI. Such cattle and bison would be exempt from the requirement under the following circumstances:

- They are moved directly to a recognized slaughtering establishment, or directly to an approved livestock facility approved to handle ''for slaughter only'' animals and then directly to a recognized slaughtering establishment, and they are accompanied by an owner-shipper statement.
- They are moved directly to an approved livestock facility with an owner-shipper statement and do not move interstate from the facility unless accompanied by an ICVI.
- They are moved from the farm of origin for veterinary medical examination or treatment and returned to the farm of origin without change in ownership.
- They are moved directly from one State through another State and back to the original State.
- They are moved as a commuter herd with a copy of the commuter herd agreement.
- Additionally, cattle and bison under 18 months of age may be moved between shipping and receiving States or Tribes with documentation other than an ICVI, *e.g.,* a brand inspection certificate when a brand is used for identification, as agreed upon by animal health officials in the shipping and receiving States or Tribes.

A number of these exceptions, such as those for movement of commuter herds, transit through a second State and return to the original State, and movement to slaughter, dovetail with the exemptions allowed from official identification requirements. Because of the other safeguards associated with such interstate movements, an ICVI is not considered to be necessary. The exemption for movement between States or Tribes that have agreed upon an alternative form of documentation would not be allowed for sexually intact cattle or bison 18 months of age or older. Adult breeding cattle moving interstate warrant inspection, which must be documented on the ICVI, because their longevity and contacts with other livestock make them a higher risk for exposure to and transmission of disease.

Official identification numbers of cattle or bison moving interstate would have to be recorded on the ICVI or other documentation accompanying them, except under the following circumstances:

- If the cattle or bison are moved from an approved livestock facility directly to a recognized slaughtering establishment; or
- If the cattle and bison are sexually intact cattle or bison under 18 months of age, or are steers or spayed heifers of any age. This exception would not apply, however, to sexually intact dairy cattle of any age or to cattle or bison used for rodeo, exhibition, or recreational purposes.

We recognize that recording identification of feeder cattle and bison in ICVIs and other documentation would significantly slow commerce in those animals, which are often moved in large numbers. The other requirements proposed for these animals will nevertheless improve their traceability. Requiring official identification numbers for other cattle and bison to be recorded on ICVIs is a priority given their longer lifespans and increased opportunity for commingling with animals at different locations.

Horses and other equine species moving interstate would have to be accompanied by an ICVI or other interstate movement document as agreed to by the States or Tribes involved in the movement. Equines being commercially shipped to slaughter would have to be accompanied by documentation in accordance with part 88. Equine infectious anemia (EIA) reactors would have to be accompanied by documentation as required by 9 CFR part 75. Under the existing regulations, equines other than slaughter equines or EIA reactors generally are not required to be accompanied by documentation for interstate movement. The more comprehensive documentation requirements we are proposing here would improve traceability by closing a major gap in the regulations.

Poultry moving interstate would have to be accompanied by an ICVI, with some exceptions similar to those allowed for cattle and bison when other safeguards are in place. Specifically, the proposed exceptions to the ICVI requirements for poultry are as follows:

- The poultry are from a flock participating in the NPIP and are accompanied by the documentation required under the NPIP regulations for participation in that program;
- The poultry are moved directly to a recognized slaughtering establishment;
- The poultry are moved from the farm of origin for veterinary medical examination, treatment, or diagnostic purposes and either returned to the farm of origin without change in ownership or euthanized and disposed of at the veterinary facility;
- The poultry are moved directly from one State through another State and back to the original State;
- The poultry are moved between the shipping and receiving States or Tribes with a VS Form 9–3 or documentation other than an ICVI, as agreed upon by animal health officials in the shipping and receiving States or Tribes; or
- The poultry are moved under permit in accordance with 9 CFR part 82.

As we have noted previously, in the overview section of this preamble, traceability-related requirements in our existing regulations for some species of covered livestock, *e.g.,* sheep and goats, swine, and captive cervids, are already sufficiently comprehensive and rigorous at this time. For that reason, this proposed rule would not alter existing documentation requirements for sheep and goats, swine, and captive cervids moving interstate. Sheep and goats moved interstate would have to be accompanied by documentation as required by the scrapie regulations in part 79. Swine moved interstate would have to be accompanied by documentation in accordance with § 71.19. Captive cervids moving interstate would have to be accompanied by documentation as required under part 77. Captive cervids moving interstate from an accredited-free State would be subject to the proposed traceability requirements and, therefore, would have to have an ICVI or other movement document.

APHIS requests comment on the proposed requirement that covered livestock being moved interstate be accompanied by an ICVI or other movement documentation. In particular, we request comment on the benefits of veterinary inspection in the cases described above when ICVIs would be used. Will veterinary inspection, especially inspection of large herds, yield substantial benefits? We request comment on whether the proposal for veterinary inspection will impose costs on businesses, particularly on small or very small businesses.

Performance Standards for Traceability

When livestock are found to be infected with or exposed to a disease, we take action to prevent that animal from spreading it via interstate movement. Because the infected or exposed animal may already have had contact with other animals, however, we need to determine which other animals have had contact with the sick or exposed livestock, find them, and take appropriate actions to be sure they do not spread the disease. To do this, we need to trace the prior movements of the livestock found to be infected or exposed and then trace the forward movements of animals with which they may have come into contact. Our ability to monitor, control, and eradicate livestock diseases is contingent upon our being able to trace livestock movements forward and backward. Our focus in this rulemaking is on tracing interstate animal movements.

Though we do not now have the data necessary to establish performance standards for States and Tribes and are not proposing to add any to the regulations at this time, in the paragraphs that follow, we discuss our current thinking on the issue. Additional information regarding performance standards is available on our traceability Web site at *http://www.aphis.usda.gov/traceability/.* We welcome comments from the public on all aspects of this issue. We propose to reserve a section in the regulations for the performance standards that we plan to establish through a future rulemaking.

To evaluate a State's or Tribe's ability to meet the traceability performance standards, APHIS would make use of animals it selects as ''reference animals.'' APHIS could randomly select reference animals for a test exercise or could select animals that were included in an actual disease traceback investigation as reference animals. However, animals would be eligible to be used as reference animals only if they were moved interstate on or after the date they are required to be officially identified and only if they are identified with an official identification number issued on or after the effective date of the final rule for this proposed rule. These eligibility criteria would ensure that animals moved interstate prior to this rulemaking would not be included in the pool of reference animals. States and Tribes would be evaluated on their ability to trace animals moved in accordance with the new regulations only.

As we currently envision the performance standards, States and Tribes would have to be able to accomplish the four activities listed below, which are necessary components of a trace investigation, within a specified timeframe for any species covered under the traceability regulations. These activities would measure a State's or Tribe's ability to trace the movement of reference animals backwards or forwards as necessary, depending on whether it is a shipping or receiving State or Tribe.

- The receiving State or Tribe of a reference animal determines the State or Tribe in which the animal was officially identified and notifies that State or Tribe of the reference animal's official identification number.
- The State or Tribe where a reference animal was officially identified confirms that it has documentation that the official identification number was issued within its jurisdiction and that it has contact information for the person who received that identification number.
- The receiving State or Tribe of a reference animal determines the State or Tribe from which the animal was moved interstate into its jurisdiction and notifies that State or Tribe of the reference animal's official identification number.
- The State or Tribe that receives notification that a reference animal moved interstate from its jurisdiction determines the address or location from which the reference animal was shipped.

We intend to conduct baseline studies by collecting information on States' and Tribes' abilities to carry out those four activities for each species covered by these regulations. The data we collect will enable us to establish firm measurements by which we could evaluate the performance of States and Tribes.

Traceability Evaluations of States and Tribes

Because we have not yet finalized the performance standards, we are not proposing at this time to add to the regulations a description of the process we will use to evaluate States' and Tribes' performance or requirements for conducting such evaluations. In the paragraphs that follow, however, we discuss our current thinking on those issues. We welcome comments from the public regarding the evaluation process. We are reserving an additional section in the regulations for evaluation requirements that we plan to establish through future rulemaking.

Regardless of the final form the evaluation requirements take, we anticipate that Tribal lands within a State's boundaries would be included in the evaluation of that State unless the Tribe has a separate traceability system. To ensure equal treatment for Tribes, any Tribe wishing to have a separate traceability system and be evaluated separately from the State(s) in which its lands are located could request separate consideration at any time.

As we currently envision the evaluation process, if a State or Tribe did not meet all traceability performance standards for a particular species but performed within what we determined to be an acceptable range, the State or Tribe would have opportunity to take corrective action without penalty. APHIS would reevaluate the State or Tribe upon request of State or Tribal animal health officials. If the State or Tribe did not request reevaluation or failed to meet all traceability performance standards for the species after 3 years, additional traceability requirements, which are described below, could be applied to the interstate movement of the applicable species from the State or Tribe. Animal movements from States or Tribes that fail to meet performance standards may be associated with a greater risk of spreading disease than animal movements from compliant States or Tribes. For that reason, the need to trace animal movements from the former category of States and Tribes may be more acute, necessitating more stringent traceability requirements.

If an evaluation were to show that a State or Tribe's performance was not within a defined acceptable range for a species, the Administrator would notify the State or Tribe in writing that additional traceability requirements would apply to the interstate movement of the applicable species from the State or Tribe beginning 60 days from the date of notification. The State or Tribe could appeal the decision in writing within 15 days of receiving notification. The appeal would have to provide all of the facts and reasons the State or Tribe believes that the Administrator should consider in rejecting the results of the evaluation and ordering a new one. The Administrator would grant or deny the appeal in writing, as promptly as circumstances allow, stating the reasons for the decision.

Any additional traceability requirements for States or Tribes not performing within an acceptable range would be established by the Administrator in each case, taking into consideration the results of the traceability evaluation, in order to enhance traceability of the species for which the performance standards are not being met. The additional requirements could include, but would not be limited to, requirements to apply or record official identification that would otherwise not be required under the regulations, or requirements for supplemental documentation, such as movement permits. APHIS would reevaluate the State or Tribe at the request of State or Tribal animal health officials. So that the public would be informed, APHIS would announce the imposition or removal of any additional traceability requirements through documents published in the **Federal Register**.

Preemption (§ 90.8)

Our proposed traceability regulations would preempt State, Tribal, and local laws and regulations that are in conflict with them, with certain exceptions. In keeping with our objective of allowing States and Tribes to develop the traceability systems that work best for them, we would allow them the latitude to impose some additional requirements for the movement of animals into their jurisdictions, so long as those additional requirements are consistent with our traceability goals and do not interfere with the right of another State or Tribe to determine what kind of traceability system to employ. Specifically, we would allow States and Tribes to require that covered livestock moving into their jurisdictions be officially identified even if those covered livestock are exempt from official identification requirements under these proposed regulations. The State or Tribe of destination could not, however, specify an official identification device or method, such as an RFID tag, that would have to be used by the shipping State or Tribe. Nor could the State or Tribe of destination compel the shipping State or Tribe to develop a particular kind of traceability system or change its existing system in order to meet the requirements of the State or Tribe of destination.

Changes to 9 CFR Part 71

The addition of the new traceability part would necessitate some changes to part 71, which contains general provisions pertaining to the interstate movement of livestock. In § 71.1, we would revise the definitions of *animal identification number (AIN), group/lot identification number (GIN), livestock, official eartag, official identification device or method,* and *premises identification number (PIN*) so that they would match the definitions we are proposing in our traceability regulations. We would also replace the existing definitions of *moved (movement) in interstate commerce* and *United States Department of Agriculture backtag,* respectively, with our proposed definitions of *move* and *United States Department of Agriculture (USDA) approved backtag* and add to § 71.1 the definitions of *flock-based* *number system, flock identification number (FIN), National Uniform Eartagging System (NUES*), and *official identification number* that we are proposing to include in part 90. We would remove and reserve § 71.18, which pertains to the identification of cattle aged 2 years and over for interstate movement, and § 71.22, which addresses the removal and loss of official identification devices. Both sets of requirements are addressed in the proposed new traceability part. Finally, we would make some minor editorial changes to § 71.19, so that the terminology used therein would be consistent with that of proposed part 90.

Changes to 9 CFR Parts 77 and 78

Adding the proposed traceability requirements to the regulations also necessitates some changes to the existing regulations pertaining to tuberculosis, in part 77, and brucellosis, in part 78. For species other than cattle and bison, the proposed traceability regulations, in most cases, refer the reader to the appropriate existing regulations for those species; for cattle and bison, however, the proposed traceability regulations will impose additional and, in some cases, slightly different requirements. To avoid potential conflicts with the traceability requirements, we are therefore proposing some amendments to the tuberculosis and brucellosis regulations. In both parts 77 and 78, we are proposing to amend certain definitions. We are also proposing to amend the regulatory text in parts 77 and 78 to incorporate the new and amended definitions and to ensure that the requirements in those parts pertaining to official identification of animals moving interstate and documentation of such movements are consistent with, when not more stringent than, the requirements in the proposed traceability part.

We are proposing to amend § 77.2, which contains definitions applicable to all of part 77, to revise the definitions of *animal identification number (AIN*), *livestock, official eartag, officially identified,* and *premises identification number (PIN),* remove the definitions of *certificate, moved, moved directly,* and *premises of origin identification,* and add definitions of *directly, interstate certificate of veterinary inspection (ICVI), location-based numbering system, location identification (LID) number, move, National Uniform Eartagging System (NUES), official identification number, recognized slaughtering establishment,* and *United States Department of Agriculture (USDA) approved backtag* as discussed above. In § 77.5, which contains definitions applicable to cattle and bison, we are proposing to remove the definition of *approved slaughtering establishment* and add a definition of *recognized slaughtering establishment* in its place.

The existing definition of *officially identified* in § 77.2, referred to earlier under our discussion of official identification devices and methods for captive cervids, allows for the use of official eartags, tattoos and hot brands as means of official identification. We propose to define *officially identified* in § 77.2 as identified by means of an official eartag. As noted previously, eliminating tattoos and hot brands as means of official identification in part 77 would avoid a potential conflict between our tuberculosis regulations and our proposed traceability requirements.

Many of the amendments we are proposing to the remainder of part 77 are intended to incorporate the revised or new definitions into the regulatory text. Throughout part 77, sections listing interstate movement requirements (for cattle and bison, §§ 77.10, 77.12, 77.14, and 77.16; for captive cervids, §§ 77.25, 77.27, 77.29, 77.31, 77.32, 77.35, 77.36, 77.37, and 77.40) contain references to certificates and/or approved slaughtering establishments. Wherever those terms occur, the text would be amended to refer to ICVIs and recognized slaughtering establishments instead.

We are proposing some additional changes to make the regulations clearer. Current § 77.8 states that cattle and bison originating in an accredited-free State or zone may be moved interstate without restriction. Even under the existing regulations, that provision is not entirely accurate, since cattle over 2 years of age must meet the requirements of § 71.18 to move interstate. We therefore are proposing to amend § 77.8 to state that cattle and bison from an accredited free State or zone may be moved interstate in accordance with proposed part 90 (as noted earlier, proposed traceability requirements for cattle and bison would replace the existing ones in § 71.18) and without further restriction under the tuberculosis regulations.

Other proposed changes to part 77 are intended to eliminate possible conflicts with the proposed traceability regulations while also streamlining the existing ones. Under current § 77.23, captive cervids from an accredited-free State or zone may be moved interstate without restriction. We are proposing to amend that section to state that captive cervids may move interstate from an accredited-free State or zone in accordance with the traceability regulations, (*i.e.,* as noted previously, they would no longer be exempted from official identification and documentation requirements) and without further restriction under the tuberculosis regulations. In a number of places the tuberculosis regulations allow for interstate movement of cattle and bison to slaughter (§§ 77.10, 77.12, 77.14) without the USDA approved backtags required under the proposed traceability regulations or for interstate movement of captive cervids (§§ 77.25, 77.27, 77.29, 77.32, 77.35, 77.36, and 77.37) either to slaughter without backtags or to other destinations without the official identification required under the proposed traceability regulations. We are proposing to amend these various sections to indicate that animals moving interstate under the tuberculosis regulations must, at a minimum, meet the traceability requirements of proposed part 90, *e.g.,* have backtags if being moved to slaughter, and meet any additional conditions that apply under the tuberculosis regulations. Where the existing regulations allow premises of origin identification in lieu of official identification, *e.g.,* in §§ 77.10, 77.12, and 77.14, we would eliminate the premises-of-origin alternative to bring our tuberculosis requirements into line with our proposed traceability requirements. In some cases, the sections being amended in part 77 would undergo some limited reorganization, in order to avoid unnecessary repetition. For example, we would remove some paragraphs that focus specifically on identification of animals moving to slaughter and instead refer to those requirements in amended introductory text. The changes we are proposing to part 77 would ensure that in all cases, the identification requirements in the tuberculosis regulations would, at a minimum, be equivalent to our proposed traceability requirements.

We propose to amend § 78.1, which defines terms pertaining to the regulation of brucellosis, in a manner similar to our proposed changes to § 77.2. Specifically, we would revise the definitions of *animal identification number (AIN*), *dairy cattle, directly, market cattle identification test cattle, official eartag,* and *recognized slaughtering establishment,* remove the definitions of *certificate, official identification device or method,* and *rodeo bulls,* and add definitions of *commuter herd, commuter herd agreement, interstate certificate of* *veterinary inspection (ICVI), location-based numbering system, location identification (LID) number, National Uniform Eartagging System (NUES), official identification number, officially identified,* and *rodeo cattle.*

The existing definition of *market cattle identification test cattle* in § 78.1 defines such cattle as cows and bulls 2 years of age or over which have been moved to recognized slaughtering establishments, and test-eligible cattle which are subjected to an official test for the purposes of movement at farms, ranches, auction markets, stockyards, quarantined feedlots, or other assembly points. The definition further states that such cattle shall be identified by an official eartag and/or United States Department of Agriculture backtag prior to or at the first market, stockyard, quarantined feedlot, or slaughtering establishment they reach.

We are proposing here to define *market cattle identification test cattle* as cows and bulls 18 months of age or over which have been moved to recognized slaughtering establishments, and test-eligible cattle which are subjected to an official test for the purposes of movement at farms, ranches, auction markets, stockyards, quarantined feedlots, or other assembly points. Under the proposed definition, such cattle must be identified with an official identification device or method as specified in the proposed traceability requirements prior to or at the first market, stockyard, quarantined feedlot, or slaughtering establishment they reach. These proposed changes to the definition bring it into line with our proposed traceability requirements by lowering from 2 years to 18 months the age of the cattle to which the requirements apply. By referring the reader to the traceability requirements for official identification devices and methods, rather than specifying the tags to be used, as in the existing definition, we would eliminate the option of using a backtag as official identification for such cattle, further aligning our brucellosis regulations with our proposed traceability requirements.

Our proposed definition of *rodeo cattle*—cattle used at rodeos or competitive events—takes the place of the existing definition of *rodeo bulls* and reflects current usage. Current § 78.14 contains requirements for the interstate movement of rodeo bulls. We propose to amend § 78.14 by replacing the term rodeo bulls wherever it is used, including in the section heading, with rodeo cattle.

Other proposed changes in part 78 align the terminology used in that part with that of the proposed traceability regulations. References to certificates in §§ 78.2, 78.9, 78.12, 78.14, and 78.20 would be replaced wherever they occur with references to ICVIs. Current § 78.9(a)(3)(ii), (b)(3)(iv), and (c)(3)(iv) describe interstate movements that would be covered under our proposed definitions of *commuter herd* and *commuter herd agreement* but do not use those terms. To achieve greater consistency in our regulations, we propose to amend those paragraphs by incorporating into them the commuter herd language used in the proposed traceability regulations. As noted above, definitions of *commuter herd* and *commuter herd agreement* would be added to § 78.1.

As in part 77 of the existing regulations, there are a number of provisions in part 78, *e.g.,* in §§ 78.5, 78.6, 78.9, 78.12, 78.20, 78.21, 78.23, and 78.24, that, as currently worded, could give the reader the mistaken impression that the interstate movements referred to in those provisions are either not restricted or subject to restriction only under the brucellosis regulations. In all such instances, we are proposing to amend the text to indicate that the interstate movements referred to must also meet our proposed traceability requirements.

Current § 78.2(b)(1) charges the APHIS representative, State representative, or accredited veterinarian responsible for issuing a certificate with the task of forwarding a copy of the certificate to the State animal health official in either the State of origin or the State of destination. If the APHIS representative, State representative, or accredited veterinarian issues a permit, he or she must forward a copy to the State of destination. We propose to amend that paragraph to require the APHIS, State, or Tribal representative or accredited veterinarian issuing an ICVI or other interstate movement document used in lieu of an ICVI or a permit to forward a copy of the ICVI, other document used in lieu of an ICVI, or permit to the State animal health official of the State of origin within 5 working days. The State animal health official of the State of origin must then forward a copy of the ICVI, other interstate movement document used in lieu of an ICVI, or permit to the State animal health official of the State of destination within 5 working days. As discussed earlier, this proposed change is intended to aid State officials in conducting both traceback and trace-forward investigations, should they become necessary.

Finally, we are proposing to add to § 78.5 a statement that cattle moved interstate under permit in accordance with the brucellosis regulations are not required to be accompanied by an ICVI or owner-shipper statement. This proposed addition will help prevent unnecessary duplication of documentation or confusion about what documents are required.

Executive Order 12866 and Regulatory Flexibility Act

This proposed rule has been determined to be significant for the purposes of Executive Order 12866 and, therefore, has been reviewed by the Office of Management and Budget.

We have prepared an economic analysis for this rule. The economic analysis provides a cost-benefit analysis, as required by Executive Orders 12866 and 13653, and an initial regulatory flexibility analysis that examines the potential economic effects of this proposed rule on small entities, as required by the Regulatory Flexibility Act. The economic analysis is summarized below. Copies of the full analysis are available by contacting the person listed under **FOR FURTHER INFORMATION CONTACT** or on the Regulations.gov Web site (see **ADDRESSES** above for instructions for accessing Regulations.gov).

Based on the information we have, there is no reason to conclude that adoption of this proposed rule would result in any significant economic effect on a substantial number of small entities. However, we do not currently have all of the data necessary for a comprehensive analysis of the effects of this proposed rule on small entities. Therefore, we are inviting comments on potential effects. In particular, we are interested in determining the number and kind of small entities that may incur benefits or costs from the implementation of this proposed rule.

We are proposing to establish general traceability regulations for certain livestock moving interstate. The purpose of this rulemaking is to improve APHIS' ability to trace such livestock in the event disease is found. The benefits of this rulemaking are expected to exceed the costs overall.

While the rule would apply to cattle and bison, horses and other equine species, poultry, sheep and goats, swine, and captive cervids (referred to below as covered livestock), the focus of this analysis is on expected economic effects for the beef and dairy cattle industries. These enterprises would be most affected operationally by the rule. For the other species, APHIS would largely maintain and build on the identification requirements of existing disease program regulations.

APHIS requests comment on this determination. We invite comment on whether the proposed rule would have significant effect on the poultry industry or other affected industries. We particularly welcome any quantified estimates of impacts that the proposed rule might have.

Costs for cattle producers are estimated in terms of activities that would need to be conducted for official animal identification and issuance of an ICVI, or other movement documentation, for covered livestock moved interstate. Incremental costs incurred are expected to vary depending upon a number of factors, including whether an enterprise does or does not already use eartags to identify individual cattle. For many operators, costs of official animal identification and ICVIs would be similar, respectively, to costs associated with current animal identification practices and the inshipment documentation currently required by individual States. Existing expenditures for these activities represent cost baselines for the private sector. To the extent that official animal identification and ICVIs would simply replace current requirements, the incremental costs of the rule for private enterprises would be minimal.

Certain animal disease traceability requirements would be implemented in stages, thereby lowering near-term costs of the program. For example, beginning on the effective date of the final rule, official identification requirements would apply only to sexually intact cattle and bison 18 months of age or over, dairy cattle of any age, and cattle and bison of any age used for rodeo, exhibition, or recreational purposes. Beginning 1 year after APHIS has established that the official identification requirements for those classes of cattle and bison to which the requirements would apply in the initial stage are being implemented effectively throughout the production chain and that there is a 70 percent rate of compliance with those requirements, initially exempted cattle and bison under 18 months of age would need to be officially identified as well, but the identification numbers of these younger animals would not need to be recorded on the ICVI.

There are two main cost components for the proposed rule, using eartags to identify cattle and having certificates for cattle moved interstate. Approximately 20 percent of cattle are not currently eartagged as part of routine management practices. Annual incremental costs of official identification for cattle enterprises are estimated to total from $12.5 million to $30.5 million, assuming producers who are not already using official identification would tag their cattle as an activity separate from other routine management practices. More likely, producers who are not already using official eartags can be expected to combine tagging with other routine activities such as vaccination or de-worming, thereby avoiding the costs associated with working cattle through a chute an additional time. Under this second scenario, the total incremental cost of official identification would be about $3.5 million.

All States currently require a certificate of veterinary inspection, commonly referred to as a health certificate, for the inshipment from other States of breeder cattle, and 48 States require one for feeder cattle. Annual incremental costs of the proposed rule for ICVIs are estimated to range between $2 million and $3.8 million. If States currently requiring documentation other than ICVIs, such as owner-shipper statements or brand certificates, continue to accept these documents in lieu of an ICVI, as permitted by this proposed rule, the ICVI requirement in this proposed rule would not result in any additional costs.

The combined annual costs of the rule for cattle operations of official identification and movement documentation would range between $14.5 million and $34.3 million, assuming official identification would be undertaken separately from other routine management practices; or between $5.5 million and $7.3 million, assuming that tagging would be combined with other routine management practices that require working cattle through a chute.

Currently, States and Tribes bear responsibilities for the collection, maintenance, and retrieval of data on interstate livestock movements. These responsibilities would be maintained under the proposed rule, but the way they are administered would likely change. Based on availability, Federal funding would be allocated to assist States and Tribes as necessary in automating data collection, maintenance, and retrieval to advance animal disease traceability.

Direct benefits of improved traceability include the public and private cost savings expected to be gained under the proposed rule. Case studies for bovine tuberculosis, bovine brucellosis, and bovine spongiform encephalopathy (BSE) illustrate the inefficiencies currently often faced in tracing disease occurrences due to inadequate animal identification and the potential gains in terms of cost savings that may derive from the proposed rule.

Benefits of the proposed traceability system are for the most part potential benefits that rest on largely unknown probabilities of disease occurrence and reactions by domestic and foreign markets. The primary benefit of the proposed regulations would be the enhanced ability of the United States to regionalize and compartmentalize animal health issues more quickly, minimizing losses and enabling reestablishment of foreign and domestic market access with minimum delay in the wake of an animal disease event.

Having a traceability system in place would allow the United States to trace animal disease more quickly and efficiently, thereby minimizing not only the spread of disease but also the trade impacts an outbreak may have. The value of U.S. exports of live cattle in 2010 was $131.8 million, and the value of U.S. beef exports totaled $2.8 billion. The value of U.S. cattle and calf production in 2009 was $31.8 billion. The estimated incremental costs of the proposed rule for cattle enterprises—between $14.5 million and $34.3 million, assuming official identification is a separately performed activity, and between $5.5 million and $7.3 million, assuming official identification is combined with other routine management practices that require working cattle through a chute—represent about one-tenth of one percent of the value of domestic cattle and calf production. If there were an animal disease outbreak in the United States that affected our domestic and international beef markets, preservation of a very small proportion of these markets would need to be attributable to the proposed animal disease traceability program in order to justify estimated private sector costs.

Most cattle operations in the United States are small entities. USDA would ensure the rule's workability and cost effectiveness by collaborating in its implementation with representatives from States, Tribes, and affected industries.

Executive Order 12372

This program/activity is listed in the Catalog of Federal Domestic Assistance under No. 10.025 and is subject to Executive Order 12372, which requires intergovernmental consultation with State and local officials. (See 7 CFR part 3015, subpart V.)

Executive Order 13175

In accordance with Executive Order 13175, APHIS has consulted with Tribal Government officials. A tribal summary impact statement has been prepared that includes a summary of Tribal officials' concerns and of how APHIS has attempted to address them.

The tribal summary impact statement may be viewed on the Regulations.gov Web site or in our reading room. (A link to Regulations.gov and information on the location and hours of the reading room are provided under the heading **ADDRESSES** at the beginning of this proposed rule.) In addition, copies may be obtained by calling or writing to the individual listed under **FOR FURTHER INFORMATION CONTACT**.

Executive Order 12988

This proposed rule has been reviewed under Executive Order 12988, Civil Justice Reform. If this proposed rule is adopted: (1) All State and local laws and regulations that are in conflict with this rule will be preempted, except as provided in proposed § 90.8; (2) no retroactive effect will be given to this rule; and (3) administrative proceedings will not be required before parties may file suit in court challenging this rule.

Paperwork Reduction Act

In accordance with section 3507(d) of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the information collection or recordkeeping requirements included in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB). Please send written comments to the Office of Information and Regulatory Affairs, OMB, Attention: Desk Officer for APHIS, Washington, DC 20503. Please state that your comments refer to Docket No. APHIS–2009–0091. Please send a copy of your comments to: (1) Docket No. APHIS–2009–0091, Regulatory Analysis and Development, PPD, APHIS, Station 3A–03.8, 4700 River Road Unit 118, Riverdale, MD 20737–1238, and (2) Clearance Officer, OCIO, USDA, room 404–W, 14th Street and Independence Avenue, SW., Washington, DC 20250. A comment to OMB is best assured of having its full effect if OMB receives it within 30 days of publication of this proposed rule.

This proposed rule would establish general traceability regulations for cattle, bison, swine, sheep, goats, equines, captive cervids, and poultry moving interstate. As a result of this rulemaking, such livestock that are moved interstate would have to be officially identified and accompanied by an ICVI or other documentation, unless specifically exempted from those requirements. The proposed regulations specify approved forms of official identification for each covered species but would allow covered livestock to be moved between shipping and receiving States or Tribes with another form of identification, as agreed upon by animal health officials in the shipping and receiving jurisdictions.

The proposed rule would place the greatest information collection burden on the cattle industry, because that sector has the greatest gaps in traceability and the greatest need for new traceability standards. For the other species, APHIS would largely maintain and build on the identification requirements of existing disease program regulations, and the burden associated with those disease programs is contained in information collections related to those programs.

APHIS is asking OMB to approve, for 3 years, its use of this information collection activity to facilitate animal disease traceability and support these disease control, eradication, and surveillance activities.

We are soliciting comments from the public (as well as affected agencies) concerning our proposed information collection and recordkeeping requirements. These comments will help us:

(1) Evaluate whether the proposed information collection is necessary for the proper performance of our agency's functions, including whether the information will have practical utility;

(2) Evaluate the accuracy of our estimate of the burden of the proposed information collection, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the information collection on those who are to respond (such as through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology; *e.g.*, permitting electronic submission of responses).

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 0.0855715 hours per response.

Respondents: State, Tribal, and territorial animal health officials; accredited veterinarians; breed and registry associations; producers; livestock market operators; and harvest facility employees.

Estimated Annual Number of Respondents: 197,302.

Estimated Annual Number of Responses per Respondent: 42.85397.

Estimated Annual Number of Responses: 8,455,174.

Estimated Total Annual Burden on Respondents: 723,522 hours. (Due to averaging, the total annual burden hours may not equal the product of the annual number of responses multiplied by the reporting burden per response.)

Copies of this information collection can be obtained from Mrs. Celeste Sickles, APHIS' Information Collection Coordinator, at (301) 851–2908.

E-Government Act Compliance

The Animal and Plant Health Inspection Service is committed to compliance with the E-Government Act to promote the use of the Internet and other information technologies, to provide increased opportunities for citizen access to Government information and services, and for other purposes. For information pertinent to E-Government Act compliance related to this proposed rule, please contact Mrs. Celeste Sickles, APHIS' Information Collection Coordinator, at (301) 851–2908.

List of Subjects

9 CFR Parts 71, 77, and 78

Animal diseases, Bison, Cattle, Hogs, Livestock, Poultry and poultry products, Quarantine, Reporting and recordkeeping requirements, Transportation, Tuberculosis.

9 CFR Part 90

Animal diseases, Bison, Cattle, Interstate movement, Livestock, Official identification, Reporting and recordkeeping requirements, Traceability.

Accordingly, we propose to amend 9 CFR chapter I as follows:

PART 71—GENERAL PROVISIONS

1. The authority citation for part 71 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

2. Section 71.1 is amended by revising the definitions of *animal identification number (AIN), group/lot identification number (GIN), livestock, official eartag, official identification device or method,* and *premises identification number (PIN)*, removing the definitions of *moved (movement) in interstate commerce* and *United States Department of Agriculture Backtag,* and adding definitions of *flock-based number system, flock identification number (FIN), move, National Uniform Eartagging System (NUES), official identification number,* and *United States Department of Agriculture (USDA) approved backtag* in alphabetical order to read as follows:

§ 71.1 Definitions.

* * * * *

Animal identification number (AIN). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal. The AIN consists of 15 digits, with the first 3 being the country code (840 for the United States). The alpha characters USA or the numeric code assigned to the manufacturer of the identification device by the International Committee on Animal Recording may be used as an alternative to the 840 prefix; however, only the AIN beginning with the 840 prefix will be recognized as official for use on AIN tags applied to animals on or after [*Insert date 1 year after effective date of final rule*]. The AIN beginning with the 840 prefix may be used only on animals born in the United States.

* * * * *

Flock-based number system. The flock-based number system combines a flock identification number (FIN) with a producer's unique livestock production numbering system to provide a nationally unique identification number for an animal.

Flock identification number (FIN). A nationally unique number assigned by a State, Tribal, or Federal animal health authority to a group of animals that are managed as a unit on one or more premises and are under the same ownership.

* * * * *

Group/lot identification number (GIN). The identification number used to uniquely identify a ''unit of animals'' of the same species that is managed together as one group throughout the preharvest production chain. When a GIN is used, it is recorded on documents accompanying the animals moving interstate; it is not necessary to have the GIN attached to each animal.

* * * * *

Livestock. All farm-raised animals.

* * * * *

Move. To carry, enter, import, mail, ship, or transport; to aid, abet, cause, or induce carrying, entering, importing, mailing, shipping, or transporting; to offer to carry, enter, import, mail, ship, or transport; to receive in order to carry, enter, import, mail, ship, or transport; or to allow any of these activities.

National Uniform Eartagging System (NUES). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal.

* * * * *

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. Beginning [Insert date 1 year after effective date of final rule] all official eartags applied to animals must bear the U.S. shield. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

Official identification device or method. A means approved by the Administrator of applying an official identification number to an animal of a specific species or associating an official identification number with an animal or group of animals of a specific species.

Official identification number. A nationally unique number that is permanently associated with an animal or group of animals and that adheres to one of the following systems:

(1) National Uniform Eartagging System (NUES).

(2) Animal identification number (AIN).

(3) Location-based number system.

(4) Flock-based number system.

(5) Any other numbering system approved by the Administrator for the official identification of animals.

* * * * *

Premises identification number (PIN). A nationally unique number assigned by a State, Tribal, and/or Federal animal health authority to a premises that is, in the judgment of the State, Tribal, and/ or Federal animal health authority a geographically distinct location from other premises. The PIN may be used in conjunction with a producer's own unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It may be used as a component of a group/lot identification number (GIN).

* * * * *

United States Department of Agriculture (USDA) approved backtag. A backtag issued by APHIS that provides a temporary unique identification for each animal.

§ 71.18 [Removed and Reserved]

3. Section 71.18 is removed and reserved.

§ 71.19 [Amended]

4. In § 71.19, in paragraphs (b)(2) and (d) introductory text, by removing the words ''United States Department of Agriculture backtags'' and adding the words ''United States Department of Agriculture (USDA) approved backtag'' in their place each time they occur.

§ 71.22 [Removed and Reserved]

5. Section 71.22 is removed and reserved.

PART 77—TUBERCULOSIS

6. The authority citation for part 77 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

7. Section 77.2 is amended by revising the definitions of *animal identification number (AIN), livestock, official eartag, officially identified,* and *premises identification number (PIN),* removing the definitions of *certificate, moved, moved directly,* and *premises of origin identification,* and adding definitions of *directly, interstate certificate of veterinary inspection (ICVI), location-based numbering system, location identification (LID) number, move, National Uniform Eartagging System (NUES), official identification number, recognized slaughtering establishment,* and *United States Department of Agriculture (USDA) approved backtag* in alphabetical order to read as follows:

§ 77.2 Definitions.

* * * * *

Animal identification number (AIN). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal. The AIN consists of 15 digits, with the first 3 being the country code (840 for the United States). The alpha characters USA or the numeric code assigned to the manufacturer of the identification device by the International Committee on Animal Recording may be used as an alternative to the 840 prefix; however, only the AIN beginning with the 840 prefix will be recognized as official for use on AIN tags applied to animals on or after [*Insert date 1 year after effective date of final rule*]. The AIN beginning with the 840 prefix may be used only on animals born in the United States.

* * * * *

Directly. Without unloading en route if moved in a means of conveyance and without being commingled with other animals, or without stopping, except for stops of less than 24 hours that are needed for food, water, or rest in route if the animals are moved in any other manner.

* * * * *

Interstate certificate of veterinary inspection (ICVI). An official document issued by a Federal, State, Tribal, or accredited veterinarian at the location from which animals are shipped interstate.

(1) The ICVI must show the species of animals covered by the ICVI; the number of animals covered by the ICVI; the purpose for which the animals are to be moved; the address at which the animals were loaded for interstate movement; the address to which the animals are destined; and the names of the consignor and the consignee and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined. Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal, except as provided in paragraph (2) of this definition, or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison belong to one of the classes of cattle and bison exempted under § 90.4 of this chapter from the official identification requirements of 9 CFR part 90 during the initial stage of the phase-in of those requirements). If the animals are required to be officially identified but the identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified. An ICVI may not be issued for any animal that is not officially identified if official identification is required.

(2) As an alternative to typing or writing individual animal identification on an ICVI, another document may be used to provide this information, but only under the following conditions:

(i) The document must be a State form or APHIS form that requires individual identification of animals;

(ii) A legible copy of the document must be stapled to the original and each copy of the ICVI;

(iii) Each copy of the document must identify each animal to be moved with the ICVI, but any information pertaining to other animals, and any unused space on the document for recording animal identification, must be crossed out in ink; and

(iv) The following information must be written in ink in the identification column on the original and each copy of the ICVI and must be circled or boxed, also in ink, so that no additional information can be added:

(A) The name of the document; and

(B) Either the unique serial number on the document or, if the document is not imprinted with a serial number, both the name of the person who prepared the document and the date the document was signed.

Livestock. All farm-raised animals.

Location-based numbering system. The location-based number system combines a State or Tribal issued location identification (LID) number or a premises identification number (PIN) with a producer's unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal.

Location identification (LID) number. A nationally unique number issued by a State, Tribal, and/or Federal animal health authority to a location as determined by the State or Tribe in which it is issued. The LID number may be used in conjunction with a producer's own unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It may also be used as a component of a group/lot identification number (GIN).

Move. To carry, enter, import, mail, ship, or transport; to aid, abet, cause, or induce carrying, entering, importing, mailing, shipping, or transporting; to offer to carry, enter, import, mail, ship, or transport; to receive in order to carry, enter, import, mail, ship, or transport; or to allow any of these activities.

National Uniform Eartagging System (NUES). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal.

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. Beginning [Insert date 1 year after effective date of final rule] all official eartags applied to animals must bear the U.S. shield. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

Official identification number. A nationally unique number that is permanently associated with an animal or group of animals and that adheres to one of the following systems: (1) National Uniform Eartagging System (NUES).

(2) Animal identification number (AIN).

(3) Flock-based number system.

(4) Location-based number system.

(5) Any other numbering system approved by the Administrator for the official identification of animals.

* * * * *

Officially identified. Identified by means of an official eartag.

* * * * *

Premises identification number (PIN). A nationally unique number assigned by a State, Tribal, and/or Federal animal health authority to a premises that is, in the judgment of the State, Tribal, and/or Federal animal health authority a geographically distinct location from other premises. The PIN may be used in conjunction with a producer's own livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It may be used as a component of a group/lot identification number (GIN).

Recognized slaughtering establishment. Any slaughtering facility operating under the Federal Meat Inspection Act (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (21 U.S.C. 451 *et seq.*), or State meat or poultry inspection acts.

* * * * *

United States Department of Agriculture (USDA) approved backtag. A backtag issued by APHIS that provides a temporary unique identification for each animal.

* * * * *

8. Section 77.5 is amended by removing the definition of *approved slaughtering establishment* and adding a definition of *recognized slaughtering establishment* in alphabetical order to read as follows:

§ 77.5 Definitions.

* * * * *

Recognized slaughtering establishment. Any slaughtering facility operating under the Federal Meat Inspection Act (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (21 U.S.C. 451 *et seq.*), or State meat or poultry inspection acts.

* * * * *

9. Section 77.8 is revised to read as follows:

§ 77.8 Interstate movement from accredited-free States and zones.

Cattle or bison that originate in an accredited-free State or zone may be moved interstate in accordance with 9 CFR part 90 without further restriction under this part.

10. Section 77.10 is revised to read as follows:

§ 77.10 Interstate movement from modified accredited advanced States and zones.

Cattle or bison that originate in a modified accredited advanced State or zone, and that are not known to be infected with or exposed to tuberculosis, may be moved interstate only in accordance with 9 CFR part 90 and, if moved anywhere other than directly to slaughter at a recognized slaughtering establishment, under one of the following additional conditions:

(a) The cattle or bison are sexually intact heifers moved to an approved feedlot, or are steers or spayed heifers, and are officially identified.

(b) The cattle or bison are from an accredited herd, are officially identified, and are accompanied by an ICVI stating that the accredited herd completed the testing necessary for accredited status with negative results within 1 year prior to the date of movement.

(c) The cattle or bison are sexually intact animals; are not from an accredited herd; are officially identified; and are accompanied by an ICVI stating that they were negative to an official tuberculin test conducted within 60 days prior to the date of movement.

(Approved by the Office of Management and Budget under control numbers 0579–0146, 0579–0220, and 0579–0229)

11. Section 77.12 is revised to read as follows:

§ 77.12 Interstate movement from modified accredited States and zones.

Cattle or bison that originate in a modified accredited State or zone, and that are not known to be infected with or exposed to tuberculosis, may be moved interstate only in accordance with 9 CFR part 90 and, if moved anywhere other than directly to slaughter at a recognized slaughtering establishment, under one of the following additional conditions:

(a) The cattle or bison are sexually intact heifers moved to an approved feedlot, or are steers or spayed heifers; are officially identified, and are accompanied by an ICVI stating that they were classified negative to an official tuberculin test conducted within 60 days prior to the date of movement.

(b) The cattle or bison are from an accredited herd, are officially identified, and are accompanied by an ICVI stating that the accredited herd completed the testing necessary for accredited status with negative results within 1 year prior to the date of movement.

(c) The cattle or bison are sexually intact animals; are not from an accredited herd; are officially identified; and are accompanied by an ICVI stating that the herd from which they originated was negative to a whole herd test conducted within 1 year prior to the date of movement and that the individual animals to be moved were negative to an additional official tuberculin test conducted within 60 days prior to the date of movement, except that the additional test is not required if the animals are moved interstate within 60 days following the whole herd test.

(Approved by the Office of Management and Budget under control number 0579–0146)

12. Section 77.14 is revised to read as follows:

§ 77.14 Interstate movement from accreditation preparatory States and zones.

Cattle or bison that originate in an accreditation preparatory State or zone, and that are not known to be infected with or exposed to tuberculosis, may be moved interstate only in accordance with 9 CFR part 90 and, if moved anywhere other than directly to slaughter at a recognized slaughtering establishment, under one of the following additional conditions:

(a) The cattle or bison are sexually intact heifers moved to an approved feedlot, or are steers or spayed heifers; are officially identified; and are accompanied by an ICVI stating that the herd from which they originated was negative to a whole herd test conducted within 1 year prior to the date of movement and that the individual animals to be moved were negative to an additional official tuberculin test conducted within 60 days prior to the date of movement; *Except that:* The additional test is not required if the animals are moved interstate within 6 months following the whole herd test.

(b) The cattle or bison are from an accredited herd; are officially identified; and are accompanied by an ICVI stating that the accredited herd completed the testing necessary for accredited status with negative results within 1 year prior to the date of movement and that the animals to be moved were negative to an official tuberculin test conducted within 60 days prior to the date of movement.

(c) The cattle or bison are sexually intact animals; are not from an accredited herd; are officially identified; and are accompanied by an ICVI stating that the herd from which they originated was negative to a whole herd test conducted within 1 year prior to the date of movement and that the individual animals to be moved were negative to two additional official tuberculin tests conducted at least 60 days apart and no more than 6 months apart, with the second test conducted within 60 days prior to the date of movement; *Except that:* The second additional test is not required if the animals are moved interstate within 60 days following the whole herd test.

(Approved by the Office of Management and Budget under control number 0579–0146)

§ 77.16 [Amended]

13. Section 77.16 is amended by removing the words ''an approved'' and adding the words ''a recognized'' in their place.

§ 77.17 [Amended]

14. Section 77.17 is amended as follows:

a. In paragraphs (a) introductory text and (b) introductory text, by removing the words ''an approved'' and adding the words ''a recognized'' in their place.

b. In paragraph (a)(4), by removing the words ''transportation document'' and adding the words ''VS Form 1–27'' in their place.

c. In paragraph (c), by removing the words ''to an approved slaughtering establishment'' and adding the words ''to a recognized slaughtering establishment in accordance with 9 CFR part 90'' in their place.

15. Section 77.23 is revised to read as follows:

§ 77.23 Interstate movement from accredited-free States and zones.

Notwithstanding any other provisions of this part, captive cervids that originate in an accredited-free State or zone may be moved interstate in accordance with 9 CFR part 90 and without further restriction under this part.

16. Section 77.25 is revised to read as follows:

§ 77.25 Interstate movement from modified accredited advanced States and zones.

Captive cervids that originate in a modified accredited advanced State or zone, and that are not known to be infected with or exposed to tuberculosis, may be moved interstate only in accordance with 9 CFR part 90 and, if moved anywhere other than directly to slaughter at a recognized slaughtering establishment, under one of the following additional conditions:

(a) The captive cervids are from an accredited herd, qualified herd, or monitored herd; are officially identified; and are accompanied by an ICVI stating that the herd completed the requirements for accredited herd, qualified herd, or monitored herd status within 24 months prior to the date of movement.

(b) The captive cervids are officially identified and are accompanied by an ICVI stating that they were negative to an official tuberculin test conducted within 90 days prior to the date of movement.

(Approved by the Office of Management and Budget under control number 0579–0146)

17. Section 77.27 is revised to read as follows:

§ 77.27 Interstate movement from modified accredited States and zones.

Except for captive cervids from a qualified herd or monitored herd, as provided in §§ 77.36 and 77.37, respectively, captive cervids that originate in a modified accredited State or zone, and that are not known to be infected with or exposed to tuberculosis, may be moved interstate only in accordance with 9 CFR part 90 and, if moved anywhere other than directly to slaughter at a recognized slaughtering establishment, under one of the following additional conditions:

(a) The captive cervids are from an accredited herd, are officially identified, and are accompanied by an ICVI stating that the accredited herd completed the testing necessary for accredited status with negative results within 24 months prior to the date of movement.

(b) The captive cervids are sexually intact animals; are not from an accredited herd; are officially identified; and are accompanied by an ICVI stating that the herd from which they originated was negative to a whole herd test conducted within 1 year prior to the date of movement and that the individual animals to be moved were negative to an additional official tuberculin test conducted within 90 days prior to the date of movement; *Except that:* The additional test is not required if the animals are moved interstate within 6 months following the whole herd test.

(Approved by the Office of Management and Budget under control number 0579–0146)

18. Section 77.29 is revised to read as follows:

§ 77.29 Interstate movement from accreditation preparatory States and zones.

Except for captive cervids from a qualified herd or monitored herd, as provided in §§ 77.36 and 77.37, respectively, captive cervids that originate in an accreditation preparatory State or zone, and that are not known to be infected with or exposed to tuberculosis, may be moved interstate only in accordance with 9 CFR part 90 and, if moved anywhere other than directly to slaughter at a recognized slaughtering establishment, under one of the following additional conditions:

(a) The captive cervids are from an accredited herd; are officially identified; and are accompanied by an ICVI stating that the accredited herd completed the testing necessary for accredited status with negative results within 24 months prior to the date of movement and that the individual animals to be moved were negative to an official tuberculin test conducted within 90 days prior to the date of movement.

(b) The captive cervids are sexually intact animals; are not from an accredited herd; are officially identified; and are accompanied by an ICVI stating that the herd from which they originated was negative to a whole herd test conducted within 1 year prior to the date of movement and that the individual animals to be moved were negative to two additional official tuberculin tests conducted at least 90 days apart and no more than 6 months apart, with the second test conducted within 90 days prior to the date of movement; *Except that:* The second additional test is not required if the animals are moved interstate within 6 months following the whole herd test.

(Approved by the Office of Management and Budget under control number 0579–0146)

§ 77.31 [Amended]

19. Section 77.31 is amended by removing the words ''an approved'' and adding the words ''a recognized'' in their place.

§ 77.32 [Amended]

20. Section 77.32 is amended as follows:

a. In paragraph (a), by removing the words ''§§ 77.25(a), 77.27(a), 77.29(a), and 77.31(d)'' and adding the words ''9 CFR part 90'' in their place.

b. In paragraph (c), by removing the words ''accompanied by a certificate'' and adding the words ''officially identified and accompanied by an ICVI'' in their place.

21. In § 77.35, paragraph (b) is revised to read as follows:

§ 77.35 Interstate movement from accredited herds.

* * * * *

(b) *Movement allowed.* Except as provided in § 77.23 with regard to captive cervids that originate in an accredited-free State or zone, and except as provided in § 77.31 with regard to captive cervids that originate in a nonaccredited State or zone, a captive cervid from an accredited herd may be moved interstate without further tuberculosis testing only if it is officially identified and is accompanied by an ICVI, as provided in § 77.32(c), that includes a statement that the captive cervid is from an accredited herd. If a group of captive cervids from an accredited herd is being moved interstate together to the same destination, all captive cervids in the group may be moved under one ICVI.

* * * * *

22. In § 77.36, paragraphs (b)(2), (b)(3), and (b)(4) are revised to read as follows:

§ 77.36 Interstate movement from qualified herds.

* * * * *

(b) * * *

(2) The captive cervid is officially identified and is accompanied by an ICVI, as provided in § 77.32(c), that includes a statement that the captive cervid is from a qualified herd. Except as provided in paragraphs (b)(3) and (b)(4) of this section, the ICVI must also state that the captive cervid has tested negative to an official tuberculosis test conducted within 90 days prior to the date of movement. If a group of captive cervids from a qualified herd is being moved interstate together to the same destination, all captive cervids in the group may be moved under one ICVI.

(3) Captive cervids under 1 year of age that are natural additions to the qualified herd or that were born in and originate from a classified herd may move without testing, provided that they are officially identified and that the ICVI accompanying them states that the captive cervids are natural additions to the qualified herd or were born in and originated from a classified herd and have not been exposed to captive cervids from an unclassified herd.

(4) Captive cervids being moved interstate for the purpose of exhibition only may be moved without testing, provided they are returned to the premises of origin no more than 90 days after leaving the premises, have no contact with other livestock during movement and exhibition, are officially identified, and are accompanied by an ICVI that includes a statement that the captive cervid is from a qualified herd and will otherwise meet the requirements of this paragraph.

* * * * *

23. In § 77.37, paragraphs (b)(2) and (b)(3) are revised to read as follows:

§ 77.37 Interstate movement from monitored herds.

* * * * *

(b) * * *

(2) The captive cervid is officially identified and is accompanied by an ICVI, as provided in § 77.32(c), that includes a statement that the captive cervid is from a monitored herd. Except as provided in paragraph (b)(3) of this section, the ICVI must also state that the captive cervid has tested negative to an

official tuberculosis test conducted within 90 days prior to the date of movement. If a group of captive cervids from a monitored herd is being moved interstate together to the same destination, all captive cervids in the group may be moved under one ICVI.

(3) Captive cervids under 1 year of age that are natural additions to the monitored herd or that were born in and originate from a classified herd may move without testing, provided that they are officially identified and that the ICVI accompanying them states that the captive cervids are natural additions to the monitored herd or were born in and originated from a classified herd and have not been exposed to captive cervids from an unclassified herd.

* * * * *

§ 77.40 [Amended]

24. In § 77.40, paragraph (a)(3) is amended by removing the words ''an approved'' and adding the words ''a recognized'' in their place.

PART 78—BRUCELLOSIS

25. The authority citation for part 78 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

26. Section 78.1 is amended by revising the definitions of *animal identification number (AIN), dairy cattle, directly, market cattle identification test cattle, official eartag,* and *recognized slaughtering establishment,* removing the definitions of *certificate, official identification device or method,* and *rodeo bulls,* and adding definitions of *commuter herd, commuter herd agreement, interstate certificate of veterinary inspection (ICVI), location-based numbering system, location identification (LID) number, National Uniform Eartagging System (NUES), official identification number, officially identified,* and *rodeo cattle* in alphabetical order to read as follows:

§ 78.1 Definitions.

* * * * *

Animal identification number (AIN). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal. The AIN consists of 15 digits, with the first 3 being the country code (840 for the United States). The alpha characters USA or the numeric code assigned to the manufacturer of the identification device by the International Committee on Animal Recording may be used as an alternative to the 840 prefix; however, only the AIN beginning with the 840 prefix will be recognized as official for use on AIN tags applied to animals on or after [*Insert date 1 year after effective date of final rule*]. The AIN beginning with the 840 prefix may be used only on animals born in the United States.

* * * * *

Commuter herd. A herd of cattle or bison moved interstate during the course of normal livestock management operations and without change of ownership directly between two premises, as provided in a commuter herd agreement.

Commuter herd agreement. A written agreement between the owner(s) of a herd of cattle or bison and the animal health officials for the States or Tribes of origin and destination specifying the conditions required for the interstate movement from one premises to another in the course of normal livestock management operations and specifying the time period, up to 1 year, that the agreement is effective. A commuter herd agreement may be renewed annually.

* * * * *

Dairy cattle. All cattle, regardless of age or sex or current use, that are of a breed(s) typically used to produce milk or other dairy products for human consumption.

* * * * *

Directly. Without unloading en route if moved in a means of conveyance and without being commingled with other animals, or without stopping, except for stops of less than 24 hours that are needed for food, water, or rest in route if the animals are moved in any other manner.

* * * * *

Interstate certificate of veterinary inspection (ICVI). An official document issued by a Federal, State, Tribal, or accredited veterinarian at the location from which animals are shipped interstate.

(a) The ICVI must show the species of animals covered by the ICVI; the number of animals covered by the ICVI; the purpose for which the animals are to be moved; the address at which the animals were loaded for interstate movement; the address to which the animals are destined; and the names of the consignor and the consignee and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined. Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal, except as provided in paragraph (b) of this definition, or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison belong to one of the classes of cattle and bison exempted under § 90.4 of this chapter from the official identification requirements of 9 CFR part 90 during the initial stage of the phase-in of those requirements). If the animals are required to be officially identified but the identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified. An ICVI may not be issued for any animal that is not officially identified if official identification is required.

(b) As an alternative to typing or writing individual animal identification on an ICVI, another document may be used to provide this information, but only under the following conditions:

(1) The document must be a State form or APHIS form that requires individual identification of animals;

(2) A legible copy of the document must be stapled to the original and each copy of the ICVI;

(3) Each copy of the document must identify each animal to be moved with the ICVI, but any information pertaining to other animals, and any unused space on the document for recording animal identification, must be crossed out in ink; and

(4) The following information must be written in ink in the identification column on the original and each copy of the ICVI and must be circled or boxed, also in ink, so that no additional information can be added:

(i) The name of the document; and

(ii) Either the unique serial number on the document or, if the document is not imprinted with a serial number, both the name of the person who prepared the document and the date the document was signed.

Location-based number system. The location-based number system combines a State or Tribal issued location identification (LID) number or a premises identification number (PIN) with a producer's unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal.

Location identification (LID) number. A nationally unique number issued by a State, Tribal, and/or Federal animal health authority to a location as determined by the State or Tribe in which it is issued. The LID number may be used in conjunction with a producer's own unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It may also be used as a component of a group/lot identification number (GIN).

Market cattle identification test cattle. Cows and bulls 18 months of age or over which have been moved to recognized slaughtering establishments, and test-eligible cattle which are subjected to an official test for the purposes of movement at farms, ranches, auction markets, stockyards, quarantined feedlots, or other assembly points. Such cattle must be identified with an official identification device as specified in § 90.4(a) of this chapter prior to or at the first market, stockyard, quarantined feedlot, or slaughtering establishment they reach.

* * * * *

National Uniform Eartagging System (NUES). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal.

* * * * *

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. Beginning [Insert date 1 year after effective date of final rule] all official eartags applied to animals must bear the U.S. shield. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

* * * * *

Official identification number. A nationally unique number that is permanently associated with an animal or group of animals and that adheres to one of the following systems:

(1) National Uniform Eartagging System.

(2) Animal identification number (AIN).

(3) Location-based number system.

(4) Flock-based number system.

(5) Any other numbering system approved by the Administrator for the official identification of animals.

Officially identified. Identified by means of an official identification device or method approved by the Administrator.

* * * * *

Recognized slaughtering establishment. Any slaughtering facility operating under the Federal Meat Inspection Act (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (21 U.S.C. 451 *et seq.*), or State meat or poultry inspection acts.

Rodeo cattle. Cattle used at rodeos or competitive events.

* * * * *

27. Section 78.2 is revised to read as follows:

§ 78.2 Handling of certificates, permits, and ''S'' brand permits for interstate movement of animals.

(a) Any ICVI, other interstate movement document used in lieu of an ICVI, permit, or ''S'' brand permit required by this part for the interstate movement of animals shall be delivered to the person moving the animals by the shipper or shipper's agent at the time the animals are delivered for movement and shall accompany the animals to their destination and be delivered to the consignee or the person receiving the animals.

(b) The APHIS representative, State representative, Tribal representative, or accredited veterinarian issuing an ICVI or other interstate movement document used in lieu of an ICVI or a permit, except for permits for entry and ''S'' brand permits, that is required for the interstate movement of animals under this part shall forward a copy of the ICVI, other interstate movement document used in lieu of an ICVI, or permit to the State animal health official of the State of origin within 5 working days. The State animal health official of the State of origin shall forward a copy of the ICVI, other interstate movement document used in lieu of an ICVI, or permit to the State animal health official of the State of destination within 5 working days.

(Approved by the Office of Management and Budget under control number 0579–0047)

28. Section 78.5 is revised to read as follows:

§ 78.5 General restrictions.

Cattle may not be moved interstate except in compliance with this subpart and with 9 CFR part 90. Cattle moved interstate under permit in accordance with this subpart are not required to be accompanied by an interstate certificate of veterinary inspection or owner-shipper statement.

29. Section 78.6 is revised to read as follows:

§ 78.6 Steers and spayed heifers.

Steers and spayed heifers may be moved interstate in accordance with 9 CFR part 90 and without further restriction under this subpart.

30. Section 78.9 is amended as follows:

a. In the introductory text, by revising the first sentence to read as set forth below.

b. By revising paragraphs (a)(3)(ii), (a)(3)(iii), (b)(3)(i), (b)(3)(ii), (b)(3)(iv), (c)(1)(i), (c)(1)(ii), (c)(1)(iv)(A), (c)(1)(vi)(A), (c)(2)(ii)(A), (c)(3)(i), (c)(3)(ii), (c)(3)(iv), (d)(1)(i), (d)(1)(ii), (d)(1)(iv)(A), (d)(1)(vi)(A), (d)(2)(ii)(A), and (d)(3) to read as set forth below.

§ 78.9 Cattle from herds not known to be affected.

Male cattle which are not test eligible and are from herds not known to be affected may be moved interstate without further restriction under this subpart. * * *

(a) * * *

(3) * * *

(ii) Such cattle are moved interstate as part of a commuter herd in accordance with a commuter herd agreement.

(iii) Such cattle are moved interstate accompanied by an ICVI which states, in addition to the items specified in § 78.1, that the cattle originated in a Class Free State or area.

(b) * * *

(3) * * *

(i) Such cattle originate in a certified brucellosis-free herd and are accompanied interstate by an ICVI which states, in addition to the items specified in § 78.1, that the cattle originated in a certified brucellosis-free herd; or

(ii) Such cattle are negative to an official test within 30 days prior to such interstate movement and are accompanied interstate by an ICVI which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(iv) Such cattle are moved as part of a commuter herd in accordance with a commuter herd agreement.

(c) * * *

(1) * * * (i) Such cattle may be moved interstate from a farm of origin or a nonquarantined feedlot directly to a recognized slaughtering establishment without further restriction under this subpart.

(ii) Such cattle may be moved interstate from a farm of origin directly to an approved intermediate handling facility without further restriction under this subpart.

* * * * *

(iv) * * *

(A) They are negative to an official test conducted at the specifically approved stockyard and are accompanied to slaughter by an ICVI or ''S'' brand permit which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(vi) * * *

(A) They are negative to an official test within 30 days prior to such interstate movement and are accompanied by an ICVI or ''S'' brand permit which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(2) * * *

(ii) * * *

(A) They are negative to an official test within 30 days prior to such movement and are accompanied by an ICVI which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(3) * * *

(i) Such cattle originate in a certified brucellosis-free herd and are accompanied interstate by an ICVI which states, in addition to the items specified in § 78.1, that the cattle originated in a certified brucellosis-free herd; or

(ii) Such cattle are negative to an official test within 30 days prior to interstate movement, have been issued a permit for entry, and are accompanied interstate by an ICVI which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(iv) Such cattle are moved interstate as part of a commuter herd in accordance with a commuter herd agreement, * * *

* * * * *

(d) * * *

(1) * * * (i) Such cattle may be moved interstate from a farm of origin or a nonquarantined feedlot directly to a recognized slaughtering establishment without further restriction under this subpart.

(ii) Such cattle may be moved interstate from a farm of origin directly to an approved intermediate handling facility without further restriction under this subpart.

* * * * *

(iv) * * *

(A) They are negative to an official test conducted at the specifically approved stockyard and are accompanied by an ICVI or ''S'' brand permit which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(vi) * * *

(A) They are negative to an official test within 30 days prior to such interstate movement and are accompanied by an ICVI or ''S'' brand permit which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(2) * * *

(ii) * * *

(A) They are negative to an official test within 30 days prior to such movement and are accompanied by an ICVI which states, in addition to the items specified in § 78.1, the test dates and results of the official tests; or

* * * * *

(3) *Movement other than in accordance with paragraphs (d)(1) or (2) of this section.*

Such cattle may be moved interstate other than in accordance with paragraphs (d)(1) or (2) of this section only if such cattle originate in a certified brucellosis-free herd and are accompanied interstate by an ICVI which states, in addition to the items specified in § 78.1, that the cattle originated in a certified brucellosis-free herd.

* * * * *

§ 78.12 [Amended]

31. Section 78.12 is amended as follows:

a. In the introductory text, by adding the words '', 9 CFR part 90,'' after the citation ''§ 78.10''.

b. In paragraph (a), by adding the word ''further'' after the word ''without''.

c. In paragraphs (d)(1)(i), (d)(2)(i), and (d)(3)(ii), by removing the words ''a certificate'' and adding the words ''an ICVI'' in their place each time they occur.

32. Section 78.14 is revised to read as follows:

§ 78.14 Rodeo cattle.

(a) Rodeo cattle that are test-eligible and that are from a herd not known to be affected may be moved interstate if:

(1) They are classified as brucellosis negative based upon an official test conducted less than 365 days before the date of interstate movement: *Provided, however, That:* The official test is not required for rodeo cattle that are moved only between Class Free States;

(2) The cattle are identified with an official eartag or any other official identification device or method approved by the Administrator in accordance with § 78.5;

(3) There is no change of ownership since the date of the last official test;

(4) An ICVI accompanies each interstate movement of the cattle; and

(5) A permit for entry is issued for each interstate movement of the cattle.

(b) Cattle that would qualify as rodeo cattle, but that are used for breeding purposes during the 365 days following the date of being tested, may be moved interstate only if they meet the requirements for cattle in this subpart and in 9 CFR part 90.

(Approved by the Office of Management and Budget under control number 0579–0047)

§ 78.20 [Amended]

33. Section 78.20 is amended by adding the words ''and with 9 CFR part 90'' after the word ''subpart''.

§ 78.21 [Amended]

34. Section 78.21 is amended by adding the word ''further'' after the word ''without''.

35. Section 78.23, paragraph (c) introductory text, is revised to read as follows:

§ 78.23 Brucellosis exposed bison.

* * * * *

(c) *Movement other than in accordance with paragraphs (a) or (b) of this section.* Brucellosis exposed bison which are from herds known to be affected, but which are not part of a herd being depopulated under part 51 of this chapter, may move without further restriction under this subpart if the bison:

* * * * *

§ 78.24 [Amended]

36. Section 78.24 is amended as follows:

a. In paragraphs (a) and (b), by adding the word ''further'' after the word ''without'' each time it occurs.

b. In paragraphs (d)(1), (d)(2), (d)(3), and (d)(4), by removing the words ''a certificate'' and adding the words ''an ICVI'' in their place each time they occur.

37. A new part 90 is added to subchapter C to read as follows:

PART 90—ANIMAL DISEASE TRACEABILITY

Sec.

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

§ 90.1 Definitions.

As used in this part:

Animal Disease Traceability General Standards Document. A document providing specific detail on, among other things, numbering systems, official identification devices, and ICVIs and other animal movement documents. The Animal Disease Traceability General Standards Document is available on the Internet at *http://www.aphis.usda.gov/traceability.*

Animal identification number (AIN). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal. The AIN consists of 15 digits, with the first 3 being the country code (840 for the United States). The alpha characters USA or the numeric code assigned to the manufacturer of the identification device by the International Committee on Animal Recording may be used as an alternative to the 840 prefix; however, only the AIN beginning with the 840 prefix will be recognized as official for use on AIN tags applied to animals on or after [*Insert date 1 year after effective date of final rule*]. The AIN beginning with the 840 prefix may be used only on animals born in the United States.

Approved livestock facility. A stockyard, livestock market, buying station, concentration point, or any other premises under State or Federal veterinary inspection where livestock are assembled and that has been approved under § 71.20 of this chapter.

Approved tagging site. A premises, authorized by APHIS, State, or Tribal animal health officials, where livestock may be officially identified on behalf of their owner or the person in possession, care, or control of the animals when they are brought to the premises.

Commuter herd. A herd of cattle or bison moved interstate during the course of normal livestock management operations and without change of ownership directly between two premises, as provided in a commuter herd agreement.

Commuter herd agreement. A written agreement between the owner(s) of a herd of cattle or bison and the animal health officials for the States or Tribes of origin and destination specifying the conditions required for the interstate movement from one premises to another in the course of normal livestock management operations and specifying the time period, up to 1 year, that the agreement is effective. A commuter herd agreement may be renewed annually.

Covered livestock. Cattle and bison, horses and other equine species, poultry, sheep and goats, swine, and captive cervids.

Dairy cattle. All cattle, regardless of age or sex or current use, that are of a breed(s) typically used to produce milk or other dairy products for human consumption.

Directly. Without unloading en route if moved in a means of conveyance and without being commingled with other animals, or without stopping, except for stops of less than 24 hours that are needed for food, water, or rest in route if the animals are moved in any other manner.

Flock-based number system. The flock-based number system combines a flock identification number (FIN) with a producer's unique livestock production numbering system to provide a nationally unique identification number for an animal.

Flock identification number (FIN). A nationally unique number assigned by a State, Tribal, or Federal animal health authority to a group of animals that are managed as a unit on one or more premises and are under the same ownership.

Group/lot identification number (GIN). The identification number used to uniquely identify a ''unit of animals'' of the same species that is managed together as one group throughout the preharvest production chain. When a GIN is used, it is recorded on documents accompanying the animals moving interstate; it is not necessary to have the GIN attached to each animal.

Interstate certificate of veterinary inspection (ICVI). An official document issued by a Federal, State, Tribal, or accredited veterinarian at the location from which animals are shipped interstate.

(1) The ICVI must show the species of animals covered by the ICVI; the number of animals covered by the ICVI; the purpose for which the animals are to be moved; the address at which the animals were loaded for interstate movement; the address to which the animals are destined; and the names of the consignor and the consignee and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined. Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal, except as provided in paragraph (b) of this definition, or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison belong to one of the classes of cattle and bison exempted under § 90.4 from the official identification requirements of this part during the initial stage of the phase-in of those requirements). If the animals are required to be officially identified but the identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified. An ICVI may not be issued for any animal that is not officially identified if official identification is required.

(2) As an alternative to typing or writing individual animal identification on an ICVI, another document may be used to provide this information, but only under the following conditions:

(i) The document must be a State form or APHIS form that requires individual identification of animals;

(ii) A legible copy of the document must be stapled to the original and each copy of the ICVI;

(iii) Each copy of the document must identify each animal to be moved with the ICVI, but any information pertaining to other animals, and any unused space on the document for recording animal identification, must be crossed out in ink; and

(iv) The following information must be written in ink in the identification column on the original and each copy of the ICVI and must be circled or boxed, also in ink, so that no additional information can be added:

(A) The name of the document; and

(B) Either the unique serial number on the document or, if the document is not imprinted with a serial number, both the name of the person who prepared the document and the date the document was signed.

Interstate movement. From one State into or through any other State.

Livestock. All farm-raised animals.

Location-based numbering system. The location-based number system combines a State or Tribal issued location identification (LID) number or a premises identification number (PIN) with a producer's unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal.

Location identification (LID) number. A nationally unique number issued by a State, Tribal, and/or Federal animal health authority to a location as determined by the State or Tribe in which it is issued. The LID number may be used in conjunction with a producer's own unique livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It may also be used as a component of a group/lot identification number (GIN).

Move. To carry, enter, import, mail, ship, or transport; to aid, abet, cause, or induce carrying, entering, importing, mailing, shipping, or transporting; to offer to carry, enter, import, mail, ship, or transport; to receive in order to carry, enter, import, mail, ship, or transport; or to allow any of these activities.

National Uniform Eartagging System (NUES). A numbering system for the official identification of individual animals in the United States that provides a nationally unique identification number for each animal.

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. Beginning [Insert date 1 year after effective date of final rule] all official eartags applied to animals must bear the U.S. shield. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

Official identification device or method. A means approved by the Administrator of applying an official identification number to an animal of a specific species or associating an official identification number with an animal or group of animals of a specific species or otherwise officially identifying an animal or group of animals.

Official identification number. A nationally unique number that is permanently associated with an animal or group of animals and that adheres to one of the following systems:

(1) National Uniform Eartagging System (NUES).

(2) Animal identification number (AIN).

(3) Location-based number system.

(4) Flock-based number system.

(5) Any other numbering system approved by the Administrator for the official identification of animals.

Officially identified. Identified by means of an official identification device or method approved by the Administrator.

Owner-shipper statement. A statement signed by the owner or shipper of the livestock being moved stating the location from which the animals are moved interstate; the destination of the animals; the number of animals covered by the statement; the species of animal covered; the name and address of the owner at the time of the movement; the name and address of the shipper; and the identification of each animal, as required by the regulations, unless the regulations specifically provide that the identification does not have to be recorded.

Person. Any individual, corporation, company, association, firm, partnership, society, or joint stock company, or other legal entity.

Premises identification number (PIN). A nationally unique number assigned by a State, Tribal, and/or Federal animal health authority to a premises that is, in the judgment of the State, Tribal, and/or Federal animal health authority a geographically distinct location from other premises. The PIN may be used in conjunction with a producer's own livestock production numbering system to provide a nationally unique and herd-unique identification number for an animal. It may be used as a component of a group/lot identification number (GIN).

Recognized slaughtering establishment. Any slaughtering facility operating under the Federal Meat Inspection Act (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (21 U.S.C. 451 *et seq.*), or State meat or poultry inspection acts.

United States Department of Agriculture (USDA) approved backtag. A backtag issued by APHIS that provides a temporary unique identification for each animal.

§ 90.2 General requirements for traceability.

(a) The regulations in this part apply only to covered livestock, as defined in § 90.1.

(b) No person may move covered livestock interstate or receive such livestock moved interstate unless the livestock meet all applicable requirements of this part.

(c) The regulations in this part will apply to the movement of covered livestock onto and from Tribal lands only when the movement is an interstate movement; *i.e.,* when the movement is across a State line.

(d) In addition to meeting all applicable requirements of this part, all covered livestock moved interstate must be moved in compliance with all applicable provisions of APHIS program disease regulations (subchapter C of this chapter).

(e) The interstate movement requirements in this part do not apply to the movement of covered livestock if:

(1) The movement occurs entirely within Tribal land that straddles a State line and the Tribe has a separate traceability system from the States in which its lands are located; or

(2) The movement is to a custom slaughter facility in accordance with Federal and State regulations for preparation of meat for personal consumption.

§ 90.3 Recordkeeping requirements.

(a) *Official identification device distribution records.* Any State, Tribe, accredited veterinarian, or other person or entity who distributes official identification devices must maintain for 5 years a record of the names and addresses of anyone to whom the devices were distributed.

(b) *Interstate movement records.* Approved livestock facilities must keep for at least 5 years any ICVIs or alternate documentation that is required by this part for the interstate movement of any covered livestock that enter the facility on or after [*Insert effective date of final rule*].

§ 90.4 Official identification.

(a) *Official identification devices and methods.* The Administrator has approved the following official identification devices or methods for the species listed. The Administrator may authorize the use of additional devices or methods for a specific species if he or she determines that such additional devices or methods will provide for adequate traceability.

(1) *Cattle and bison.* Cattle and bison that are required to be officially identified for interstate movement under this part must be identified by means of:

(i) An official eartag; or

(ii) Group/lot identification when a group/lot identification number (GIN) may be used.

(2) *Horses and other equine species.* Horses and other equine species that are required to be officially identified for interstate movement under this part must be identified by one of the following methods:

(i) A description sufficient to identify the individual equine, as determined by a State or Tribal animal health official in the State or Tribe of destination or APHIS representative, including, but not limited to, name, age, breed, color, gender, distinctive markings, and unique and permanent forms of identification when present (*e.g.,* brands, tattoos, scars, cowlicks, or blemishes); or

(ii) Electronic identification that complies with ISO 11784/11785; or

(iii) Digital photographs sufficient to identify the individual equine, as determined by a State or Tribal animal health official in the State or Tribe of destination or APHIS representative; or

(iv) For equines being commercially transported to slaughter, a device or method authorized by part 88 of this chapter.

(3) *Poultry.* Poultry that are required to be officially identified for interstate movement under this part must be identified by one of the following methods:

(i) Sealed and numbered leg bands in the manner referenced in the National Poultry Improvement Plan regulations (parts 145 through 147 of this chapter); or

(ii) Group/lot identification when a group/lot identification number (GIN) may be used.

(4) *Sheep and goats.* Sheep and goats that are required to be officially identified for interstate movement under this part must be identified by a device or method authorized by part 79 of this chapter.

(5) *Swine.* Swine that are required to be officially identified for interstate movement under this part must be identified by a device or method authorized by § 71.19 of this chapter.

(6) *Captive cervids.* Captive cervids that are required to be officially identified for interstate movement under this part must be identified by a device or method authorized by part 77 of this chapter.

(b) *Official identification requirements for interstate movement.*

(1) *Cattle and bison.* (i) In accordance with the schedule in paragraph (b)(1)(iii) of this section, cattle and bison moved interstate must be officially identified prior to the interstate movement, using an official identification device or method listed in paragraph (a)(1) of this section unless:

(A) The cattle and bison are moved as a commuter herd with a copy of the commuter herd agreement.

(B) The cattle and bison are moved directly from a location in one State through another State to a second location in the original State.

(C) The cattle and bison are moved interstate directly to an approved tagging site and are officially identified before commingling with cattle and bison from other premises.

(D) The cattle and bison are moved between shipping and receiving States or Tribes with another form of identification, including but not limited to brands, tattoos, and breed registry certificates, as agreed upon by animal health officials in the shipping and receiving States or Tribes.

(ii) Until the date on which the official identification requirements in this section apply to all categories of cattle and bison not specifically exempted, cattle and bison may also be moved interstate without official identification if they are moved directly to a recognized slaughtering establishment or directly to no more than one approved livestock facility approved to handle ''for slaughter only'' animals (cattle or bison that, when marketed, are presented/sold for slaughter only) and then directly to a recognized slaughtering establishment; and

(A) They are moved interstate with a USDA-approved backtag; or

(B) A USDA-approved backtag is applied to the cattle or bison at the recognized slaughtering establishment or federally approved livestock facility approved to handle ''for slaughter only'' animals.

(iii) Official identification requirements for cattle and bison will be phased in according to the schedule below. APHIS will publish a document in the **Federal Register** to announce the date upon which the requirements become effective for all cattle and bison not otherwise exempted from official identification requirements.

Date when specified cattle and bison must be officially identified for interstate movement	Classes of cattle and bison
(A) Beginning on [Insert effective date of final rule]	(*1*) All sexually intact cattle and bison 18 months of age or over. (*2*) Dairy cattle of any age. (*3*) Cattle and bison of any age used for rodeo or recreational events. (*4*) Cattle and bison of any age used for shows or exhibitions.
(B) Beginning 1 year after the date on which APHIS announces its determination that the official identification requirements are being effectively implemented throughout the production chain and that there is a 70 percent rate of compliance with those requirements for all classes of cattle that are subject to official identification requirements in the initial phase.	All cattle and bison.

(2) *Sheep and goats.* Sheep and goats moved interstate must be officially identified prior to the interstate movement unless they are exempt from official identification requirements under 9 CFR part 79 or are officially identified after the interstate movement, as provided in 9 CFR part 79.

(3) *Swine.* Swine moving interstate must be officially identified in accordance with § 71.19 of this chapter.

(4) *Horses and other equines.* Horses and other equines moving interstate must be officially identified prior to interstate movement or identified as agreed upon by the States or Tribes involved in the movement or, if being commercially transported to slaughter, in accordance with part 88 of this chapter.

(5) *Poultry.* Poultry moving interstate must be officially identified prior to interstate movement or identified as agreed upon by the States or Tribes involved in the movement.

(6) *Captive cervids.* Captive cervids moving interstate must be officially identified prior to interstate movement in accordance with part 77 of this chapter.

(c) *Use of more than one official identification device or method.* Beginning on [Insert effective date of final rule], no more than one official identification device or method may be applied to an animal; except that:

(1) A State or Tribal animal health official or an area veterinarian in charge may approve the application of a second official identification device in specific cases when the need to maintain the identity of an animal is intensified (*e.g.,* such as for export shipments, quarantined herds, field trials, experiments, or disease surveys). Approval may not be granted merely for convenience in identifying animals. The person applying the second official identification device must record the following information about the event and maintain the record for 5 years: The

date the second official identification device is added; the reason for the additional official identification device; and the official identification numbers of both official identification devices.

(2) An eartag with an animal identification number (AIN) beginning with the 840 prefix (either radio frequency identification or visual-only tag) may be applied to an animal that is already officially identified with an eartag with a National Uniform Eartagging System number. The animal's official identification number on the existing official identification eartag must be recorded and reported in accordance with the AIN device distribution policies, which are described in the Animal Disease Traceability General Standards Document.

(3) A brucellosis vaccination eartag with a National Uniform Eartagging System number may be applied in accordance with part 78 of this chapter to an animal that is already officially identified.

(d) *Removal or loss of official identification devices.* (1) Official identification devices are intended to provide permanent identification of livestock and to ensure the ability to find the source of animal disease outbreaks. Removal of these devices, including devices applied to imported animals in their countries of origin and recognized by the Administrator as official, is prohibited except at the time of slaughter, at any other location upon the death of the animal, or as otherwise approved by the State or Tribal animal health official or an area veterinarian in charge when a device needs to be replaced.

(2) All man-made identification devices affixed to covered livestock moved interstate must be removed at slaughter and correlated with the carcasses through final inspection by means approved by the Food Safety Inspection Service (FSIS). If diagnostic samples are taken, the identification devices must be packaged with the samples and be correlated with the carcasses through final inspection by means approved by FSIS. Devices collected at slaughter must be made available to APHIS and FSIS.

(3) All official identification devices affixed to covered livestock carcasses moved interstate for rendering must be removed at the rendering facility and made available to APHIS.

(4) If an animal loses an official identification device and needs a new one, the person applying new official identification device must record the following information about the event and maintain the record for 5 years: The date the new official identification device is added; the official identification number on the device; the official identification number on the old device if known.

(e) *Replacement of official identification devices for reasons other than loss.*

(1) Circumstances under which a State or Tribal animal health official or an area veterinarian in charge may authorize replacement of an official identification device include, but are not limited to:

(i) Deterioration of the device such that loss of the device appears likely or the number can no longer be read;

(ii) Infection at the site where the device is attached, necessitating application of a device at another location (*e.g.,* a slightly different location of an eartag in the ear);

(iii) Malfunction of the electronic component of a radio frequency identification (RFID) device; or

(iv) Incompatibility or inoperability of the electronic component of an RFID device with the management system or unacceptable functionality of the management system due to use of an RFID device.

(2) Any time an official identification device is replaced, as authorized by the State or Tribal animal health official or area veterinarian in charge, the person replacing the device must record the following information about the event and maintain the record for 5 years:

(i) The date on which the device was removed;

(ii) Contact information for the location where the device was removed;

(iii) The official identification number (to the extent possible) on the device removed;

(iv) The type of device removed (*e.g.,* metal eartag, RFID eartag);

(v) The reason for the removal of the device;

(vi) The new official identification number on the replacement device; and

(vii) The type of replacement device applied.

(f) *Sale or transfer of official identification devices.* Official identification devices are not to be sold or otherwise transferred from the premises to which they were originally issued to another premises without authorization by the Administrator or a State or Tribal animal health official.

§ 90.5 Documentation requirements for interstate movement of covered livestock.

(a) The person directly responsible for animals leaving a premises for interstate movement must ensure that the animals are accompanied by an interstate certificate of veterinary inspection (ICVI) or other document required by this part for the interstate movement of animals.

(b) The APHIS representative, State or Tribal representative, or accredited veterinarian issuing an ICVI or other document required for the interstate movement of animals under this part must forward a copy of the ICVI or other document to the State or Tribal animal health official of the State or Tribe of origin within 5 working days. The State or Tribal animal health official in the State or Tribe of origin must forward a copy of the ICVI or other document to the State or Tribal animal health official the State or Tribe of destination within 5 working days.

(c) *Cattle and bison.* Cattle and bison moved interstate must be accompanied by an ICVI unless:

(1) They are moved directly to a recognized slaughtering establishment, or directly to an approved livestock facility approved to handle ''for slaughter only'' animals and then directly to a recognized slaughtering establishment, and they are accompanied by an owner-shipper statement.

(2) They are moved directly to an approved livestock facility with an owner-shipper statement and do not move interstate from the facility unless accompanied by an ICVI.

(3) They are moved from the farm of origin for veterinary medical examination or treatment and returned to the farm of origin without change in ownership.

(4) They are moved directly from one State through another State and back to the original State.

(5) They are moved as a commuter herd with a copy of the commuter herd agreement.

(6) Additionally, cattle and bison under 18 months of age may be moved between shipping and receiving States or Tribes with documentation other than an ICVI, *e.g.,* a brand inspection certificate, as agreed upon by animal health officials in the shipping and receiving States or Tribes.

(7) The official identification number of cattle or bison must be recorded on the ICVI or alternate documentation unless:

(i) The cattle or bison are moved from an approved livestock facility directly to a recognized slaughtering establishment; or

(ii) The cattle and bison are sexually intact cattle or bison under 18 months of age or steers or spayed heifers; *Except that:* This exception does not apply to sexually intact dairy cattle of any age or to cattle or bison used for rodeo, exhibition, or recreational purposes.

(d) *Sheep and goats.* Sheep and goats moved interstate must be accompanied by documentation as required by part 79 of this chapter.

(e) *Swine.* Swine moved interstate must be accompanied by documentation in accordance with § 71.19 of this chapter.

(f) *Horses and other equines.* Horses and other equines moved interstate must be accompanied by an ICVI or other interstate movement document, as agreed to by the shipping and receiving States or Tribes involved in the movement. Equines moving commercially to slaughter must be accompanied by documentation in accordance with part 88 of this chapter. Equine infectious anemia reactors moving interstate must be accompanied by documentation as required by part 75 of this chapter.

(g) *Poultry.* Poultry moved interstate must be accompanied by an ICVI unless:

(1) They are from a flock participating in the National Poultry Improvement Plan (NPIP) and are accompanied by the documentation required under the NPIP regulations (parts 145 through 147 of this chapter) for participation in that program.

(2) They are moved directly to a recognized slaughtering establishment.

(3) They are moved from the farm of origin for veterinary medical examination, treatment, or diagnostic purposes and either returned to the farm of origin without change in ownership or euthanized and disposed of at the veterinary facility.

(4) They are moved directly from one State through another State and back to the original State.

(5) They are moved between shipping and receiving States or Tribes with a VS Form 9–3 or documentation other than an ICVI, as agreed upon by animal health officials in the shipping and receiving States or Tribes.

(6) They are moved under permit in accordance with part 82 of this chapter.

(h) *Captive cervids.* Captive cervids moved interstate must be accompanied by documentation as required by part 77 of this chapter.

§ 90.6 [Reserved]

§ 90.7 [Reserved]

§ 90.8 Preemption.

The regulations in this part preempt State, Tribal, and local laws and regulations that are in conflict with them, except as described in this section. States and Tribes may require covered livestock that are exempt from official identification requirements under this part to be officially identified to be eligible for interstate movement into their jurisdictions; *Except that:* The State or Tribe of destination may not specify an official identification device or method that would have to be used if multiple devices or methods may be used under this part for a particular species, nor may the State or Tribe of destination impose requirements that would otherwise cause the State or Tribe from which the shipments originate to have to develop a particular kind of traceability system or change its existing system in order to meet the requirements of the State or Tribe of destination.

Done in Washington, DC, this 5th day of August 2011.

Edward Avalos,

Under Secretary for Marketing and Regulatory Programs.

[FR Doc. 2011–20281 Filed 8–9–11; 8:45 am]

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H.R. 1383/P.L. 112–26

Restoring GI Bill Fairness Act of 2011 (Aug. 3, 2011; 125 Stat. 268)

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